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EVALUATION AND COSTING OF NOx CONTROLS FOR EXISTING UTILITY BOILERS IN THE NESCAUM REGION

NORTHEAST STATES
FOR COORDINATED
AIR USE MANAGEMENT
(NESCAUM)

CONTROL TECHNOLOGY CENTER

EPA-453/R-92-010

EVALUATION AND COSTING OF NO_x CONTROLS FOR EXISTING UTILITY BOILERS IN THE NESCAUM REGION

CONTROL TECHNOLOGY CENTER

Sponsored by:

Emission Standards Division
Office of Air Quality Planning and Standards
U.S Environmental Protection Agency
Research Triangle Park, North Carolina 27711

Air and Energy Engineering Research Laboratory
Office of Research and Development
U.S Environmental Protection Agency
Research Triangle Park, North Carolina 27711

and

NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT

(NESCAUM)
129 Portland Street
Boston, Massachusetts 02114

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PREFACE

The Control Technology Center (CTC) was established by the U.S. Environmental Protection Agency's (EPA's) Office of Research and Development (ORD) and the Office of Air Quality Planning and Standards (OAQPS) to provide technical assistance to State and local air pollution control agencies. Several levels of assistance can be provided when appropriate. These include the following:

- CTC HOTLINE—provides quick telephone assistance on matters relating to air pollution control technology (919-541-0800)

- Engineering Assistance Projects—provide more in-depth assistance to State and local agencies when needed to address a specific air pollution problem or source

- Technical Guidance Projects—address problems or source categories of regional or national interest by developing technical guidance documents, computer software, or presentation of workshops on control technology matters

- Small Business Assistance—coordinates efforts among EPA centers participating in the Federal Small Business Assistance Program to assist State Small Business Assistance Programs

- Global Greenhouse Gases Technology Transfer Center—provides information on greenhouse gas emissions and available prevention, mitigation, and control technologies/strategies

- Data Base Assistance—provides control technology information on the RACT/BACT/LAER Clearinghouse Information System (BLIS) and CTC electronic bulletin board system (BBS). These systems are available on the OAQPS Technology Transfer Network BBS (919-541-5742)

This Technical Guidance Project addresses retrofit control options for NO_x emissions from utility boilers. The Northeast States for Coordinated Air Use Management (NESCAUM) requested and cofunded this effort. NESCAUM includes the following states: Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. NESCAUM requested this project to provide a technical basis for its member States to make Reasonably Available Control Technology (RACT) determinations for NO_x emissions from utility boilers. RACT for NO_x emissions is required in most northeastern States to attain the National Ambient Air Quality Standard for ozone. This information is also relevant to other States considering NO_x controls for utility boilers. This report presents information on the technical feasibility, performance, and cost of NO_x emission control options.

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LIST OF ABBREVIATIONS

ABB	Asea Brown Boveri. Major supplier of powerplant steam generators and gas turbines and the only supplier of tangential-fired boilers and retrofit control equipment.
ACT	Alternative Control Techniques. Documents are prepared by the EPA under requirements of 1990 CAAA.
AFDC	Allowance for funds during construction. Cost element of EPRI TAG and EPA's IAPCS.
AFS	Axial Fuel Staged. Gas/oil-fired low-NO_x burner offered by Riley.
AOFA	Advanced Overfire Air. The technique of introducing secondary air by separate air ports above the burner windbox. Designed for high velocity and effective mixing.
APS	Arizona Public Service
ASR	Axial Staged Return. Gas/oil-fired low-NO_x burner offered by Riley.
B&W	Babcock and Wilcox, a McDermott Company. Major supplier of wall- and opposed-fired utility boilers and low-NO_x combustion equipment. Manufactured the now-discontinued cyclone boilers.
BHK	Babcock Hitachi K.K. Developer of low-NO_x burner and flue gas treatment technologies.
BOOS	Burners out of service. The technique of terminating fuel flow to selected burners while increasing fuel flow to remaining burners to create a staged combustion effect that reduces NO_x.
BWE	Burmeister and Wain Energy. A European low-NO_x burner developer.
BZHRR	Burner zone heat release rate. A boiler design parameter and an important factor in establishing the uncontrolled level of NO_x and the potential for retrofit of combustion modification controls. Also known as burner zone liberation rate (BZLR).
CAA	The Clean Air Act of 1977.
CAAA	Clean Air Act Amendments of 1990.
CAT-AH	Selective Catalytic Reduction Air Heater. Selective catalytic system developed by KAH of Germany.
CCOFA	Close-Coupled Overfire Air. OFA for tangential (corner-fired) boilers that is introduced immediately above the top level of fuel nozzles and is part of the same burner windbox.

CCT	Clean Coal Technology. The national program funded by DOE, industry, and technology vendors to demonstrate new technologies to reduce NO_x and SO_2 emissions from power plants.
CCTFS	Concentric clustered tangential firing system. A low-NO_x burner design for tangential boilers that uses two levels of OFA and deeply staged combustion. Patented and used by ABB-CE (not commercially offered).
CCV	Controlled Combustion Venturi. A low-NO_x burner developed and used by Riley Stoker.
CE	Combustion Engineering. Now part of Asea Brown Boveri (ABB), the only supplier of tangential (corner)-fired boilers and controls for these units.
CEGB	Central Electricity Generating Board of the U.K.
CEM	Continuous emission monitors
CETF	Combustion and Environment Test Facility. The pilot-scale research combustion facility used by FWEC for the development of low-NO_x burners.
CF/SF	Controlled flow/Split flame. A low-NO_x burner developed and used by FWEC.
DOE	U.S. Department of Energy
DP&L	Dayton Power and Light Company
DRB-XCL®	Duel Register Burner—Type XCL. Sixth generation axial control, low-NO_x enhanced staged combustion burner developed and used by B&W.
EERC	Energy and Environmental Research Corporation, Irvine, California
EHOF	Engineering and Home Office Overhead and Fee. Cost element of EPRI TAG and EPA's IAPCS.
EIA	Energy Information Administration of the U.S. Department of Energy. Agency that documents fuel use of the electric utilities.
ENEL	Ente Nationale Energia Electrica, the Italian National Electric Utility
EPA	U.S. Environmental Protection Agency
EPDC	Electric Power Development Company of Japan
EPRI	Electric Power Research Institute, Palo Alto, California
ESEERCO	Empire State Electric Energy Research Corporation
FGD	Flue Gas Desulfurization. A variety of gas treatment technologies to scrub sulfur using wet or dry systems.

FGET	Flue Gas Exit Temperature. An important indicator of heat release and absorption in the furnace.
FGR	Flue gas recirculation. The technique of recirculating a fraction of the flue gas to the burners to reduce peak flame temperature and oxygen availability with vitiated (flue gas diluted) air for NO_x reduction. FGR can also be used for steam temperature control when introduced through furnace hopper.
FGT	Flue gas treatment. Controls that scrub or chemically destroy NO_x from the flue gas after it is already formed.
FR	Fuel ratio. The ratio of fixed carbon to volatile matter content of coals. Used as an indication of coal reactivity and rank. Also an indicator of NO_x reduction potential with combustion modifications.
FWEC	Foster-Wheeler Energy Corporation. Major supplier of face-fired utility boilers and low-NO_x combustion burners.
GF	General Facilities. Cost element of EPRI TAG and EPA's IAPCS.
GPC	Gulf of Power Company
GR	Gas reburn. A technology that uses natural gas to reduce NO_x primarily in coal-fired boilers (also referred to as natural gas reburning, NGR). Developed and marketed by Energy and Environmental Research Corporation.
GRI	Gas Research Institute, Chicago, Illinois
GR-SI	Gas Reburn and Sorbent Injection. A technology that combines NO_x and SO_2 control techniques.
HT-NR	Hitachi NO_x Reduction. A low-NO_x burner developed and used by BHK.
HZC	Hitachi Zosen Corporation. Developer and seller of NO_x reduction catalysts.
IAPCS	Integrated Air Pollution Control System. EPA's cost algorithm to determine new and retrofit costs of air pollution control at power plants.
IFNR	In-furnace NO_x reduction. A staged fuel combustion technique offered by B&W and Babcock Hitachi K.K.
IFS	Internal fuel staging. A modification to the FWEC CF/SF low-NO_x burner for further reduction in NO_x.
IHI	Ishikawajima Harima Heavy Industries. Developer and seller of NO_x reduction catalysts.
KHI	Kawasaki Heavy Industry. Developer and seller of NO_x reduction catalysts.
KP&L	Kansas Power and Light Company

LADWP	Los Angeles Department of Water and Power
LEA	Low excess air. Operation of boiler with minimal excess combustion air to optimize thermal efficiency and reduce NO_x formation.
LIMB	Limestone Injection Multistage Burner. A low-NO_x burner using staged air with limestone addition in the furnace for SO_2 reduction.
LNB	Low-NO_x burner. Burner and windbox assemblies designed to minimize the formation of NO_x by various techniques such as separated fuel jets, flue gas recirculation (FGR), and controlled air mixing. LNB designs for T-firing incorporate close-coupled OFA as part of the LNB design.
LNCB	Low-NO_x Cell Burner. A burner designed by B&W in cooperation with the Electric Power Research Institute (EPRI) for retrofit applications on existing opposed wall-fired cell boilers.
LNCFS	Low-NO_x concentric firing system. A burner modification applicable to tangential boilers to divert some of the combustion air along the waterwalls for the reduction of NO_x. Three separate configurations of LNCFS are available. Two configurations use separate overfire air. Patented and used by ABB-CE.
LNS	Low NO_x and SO_x. A process marketed by TransAlta Resources Investment Corp. for the combined reduction of NO_x and SO_2.
MACT	Mitsubishi Advanced Combustion Technology. A staged fuel combustion technique developed by MHI for in-furnace NO_x reduction.
MHI	Mitsubishi Heavy Industries. Developer of low-NO_x burner technologies for tangential boilers and FGT techniques.
MP	Monongahele Power Company
NAAQS	National Ambient Air Quality Standards
NESCAUM	Northeast States for Coordinated Air Use Management, Boston, Massachusetts
NGR	Natural gas reburning. A technology that uses natural gas to reduce NO_x primarily in coal-fired boilers (also referred to simply as GR or gas reburn).
NOXSO	A process for combined reduction of NO_x and SO_2. Developed and marketed by NOXSO Inc.
NOxOUT	The trade name for the urea-based SNCR process developed by the EPRI and marketed by Nalco-Fuel Tech.
NSPS	New Source Performance Standards. Emissions standards promulgated by the U.S. Environmental Protection Agency. Typically are not technology-forcing standards.
NSR	Normalized stoichiometric ratio. Actual mole ratio of urea to NO_x divided by the theoretical stoichiometric ratio, which is 0.5 for the reaction between urea and NO_x.

NURF	National Utility Reference File. A U.S. Environmental Protection Agency file that documents several statistical factors for the electric utilities including reported NO_x emission levels.
NYPP	New York Power Pool, Schenectady, New York
OAQPS	Office of Air Quality Planning and Standards, EPA, Research Triangle Park, North Carolina.
OFA	Overfire air. The technique of injecting separated combustion air above the main burner zone to produce staged combustion that reduces NO_x. Sometimes also called AOFA for wall-fired units.
OS	Off Stoichiometric. The combustion techniques such as BOOS and OFA that rely on reducing first stage stoichiometry to stage combustion and reduce NO_x generation.
PC	Pulverized coal. Most coal-fired utility boilers in the NESCAUM region are pulverized coal-fired boilers.
PENELEC	Pennsylvania Electric Company
PETC	Pittsburgh Energy Technology Center. Combustion research laboratory for DOE.
PG&E	Pacific Gas and Electric Company, San Francisco, California
PG-DRB	Primary Gas-Dual Register Burner. A low-NO_x burner for gas/oil boilers developed by B&W and BHK.
PM	Pollution Minimum. A low-NO_x burner developed by MHI for application on tangential boilers. Burner uses staging and FGR.
PSC	Public Service of Colorado
PSI	Public Service of Indiana
PSNM	Public Services of New Mexico
RACT	Reasonably available control technology. Required by §172 of the 1990 CAAA (Ozone Nonattainment Plan Provisions) on existing major sources in nonattainment areas. The lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.
RAP	Reduced air preheat. The technique of bypassing a fraction of the combustion air around the air preheater to reduce the peak flame temperature thus reducing NO_x.
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company

SCR	Selective catalytic reduction. The injection of chemical reagents in the flue gas for the selective reduction of NO_x to nitrogen and water.
SCS	Southern Company Services
SGR	Separate gas recirculation. A low-NO_x burner technique developed by MHI.
SNCR	Selective noncatalytic reduction. The injection of a chemical reagent at high flue gas temperatures to selectively reduce NO_x to nitrogen and water. Unlike SCR, the process does not use a catalyst.
SNRB	$SO_xNO_xRO_x$Box. A process developed by B&W that uses a hot catalytic baghouse for the combined reduction of NO_x, SO_x and flyash.
SOFA	Separate Overfire Air. A combustion technique that brings up to 25 percent of the total air entering a boiler furnace at a sufficient distance above the main burner zone to promote decay of fuel nitrogen to N_2 under reducing combustion conditions.
STS	Swirl Tertiary Separation. A low-NO_x burner for gas/oil-fired boilers developed by Riley Stoker and Deutsche Babcock.
TAG	Technical Assessment Guide. EPRI's guidelines for estimating the cost of power plant equipment.
TCR	Total capital required. Includes all capital necessary to complete the entire project.
TPC	Taiwan Power Company
TPC	Total plant cost. The cost of all purchased, fabricated, and installed equipment at power plants.
TPI	Total plant investment. Includes the escalation of construction cost and AFDC.
TSC	Two-stage combustion. A generalized term to categorize several techniques such as biased firing, BOOS, and OFA that stage combustion of fuel to reduce NO_x.
TSV	Tertiary Staged Venturi. Low NO_x burner developed and offered by Riley for turbo furnaces.
TVA	Tennessee Valley Authority
UARG	Utility Air Regulatory Group, a voluntary, nonprofit, ad hoc group representing 70 electric utility companies including utilities throughout NESCAUM, the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association.
UBC	Unburned carbon content. The content of unburned carbon in the flyash of utility boilers. An indicator of loss in combustion efficiency.

WACF Weighted average capacity factor; calculated as follows:

$$WACF = \frac{\sum CF_i \, MW_i}{\sum MW_i}$$

when:

CF_i is the capacity factor for individual boilers and MW_i is the size of individual boilers.

WFGR Windbox flue gas recirculation. A distinction made to separate the recirculation of gas to the burners versus recirculation of gas to the bottom hopper for flue gas tempering.

WI Water injection. The technique of injecting water or water/fuel emulsions to reduce the peak flame temperature thus reducing NO_x. Not a common control strategy for boilers. Generally used for gas turbines.

WSA-SNOX A combined catalytic NO_x/SO_x control technology developed by Haldor Topsoe and marketed by ABB Flakt, Inc.

SECTION 1

EXECUTIVE SUMMARY

The Northeast States for Coordinated Air Use Management (NESCAUM) requested assistance from the EPA's Control Technology Center in the Office of Air Quality Planning and Standards (OAQPS), in the development of a technical support document discussing the feasibility, performance, and costs of retrofit nitrogen oxides (NO_x) controls for utility boilers operating in the eight Northeast states that comprise the NESCAUM region. These states include Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

Section 182 of the Clean Air Act Amendments of 1990 requires that the NESCAUM states develop Reasonably Available Control Technology (RACT) standards for utility boilers and other NO_x sources. EPA's Office of Air Quality Planning and Standards is developing Alternative Control Technique (ACT) documents for stationary source categories that emit or have the potential to emit 25 tons/yr or more of NO_x. The ACT documents are required under Section 183(c) of Subpart 2 to Part D of Title I of the Clean Air Act Amendments of 1990. The findings presented in this report are intended to assist the NESCAUM states in assessing the potential and costs of NO_x RACT reductions from the existing utility boiler inventory in the NESCAUM region, and will assist the EPA in the preparation of the ACT document for NO_x controls from utility boilers.

The principal objectives of this report are to:

- Examine the population profile of the utility boilers in the NESCAUM region to segregate existing boilers according to NO_x retrofit potential
- Evaluate the commercially available controls and the reductions in NO_x achievable by each technology, including technical feasibility and emission limits
- Estimate the retrofit cost and cost effectiveness of these controls, considering site-specific factors and systemwide control applications to the extent possible
- Summarize the impact of NO_x reduction on other emissions (CO, HC, and carbon in the flyash), and estimate changes in these emissions resulting from the retrofitting of combustion controls

This report contains six sections that discuss:

- Utility boiler population profile and current estimates of total NO_x emissions (Section 2)
- Uncontrolled NO_x emissions as a function of boiler design, fuel, and age (Section 3)
- NO_x control technologies available for coal- and oil-/gas-fired boilers (Section 4)

- Cost methodology for estimating the costs of 36 scenarios for NO_x control (Section 5)

- Cost and cost effectiveness of controls as a function of several design and operating characteristics of boilers (Section 6)

- Effect of NO_x controls on emissions of CO, HC, and carbon in the flyash (Section 7)

This report uses current NO_x levels to estimate the potential NO_x reductions for individual families of boilers throughout the NESCAUM region. Appendices A and B list the NESCAUM boiler inventories for coal- and oil-/gas-fired boilers, respectively. Appendix C presents schematics of NO_x control technologies discussed in Section 4. Appendix D lists the NO_x reduction performances reported in the literature used to estimate the reduction potential for the NESCAUM boiler population. Appendix E lists current and planned selective catalytic reduction (SCR) installations worldwide. Appendices F and G provide the detailed cost analyses for the 36 retrofit cases evaluated in this study.

Because the applicability, ease of retrofit, NO_x reduction performance, and cost are very much influenced by site-specific factors that cannot be taken fully into account without a site-by-site retrofit analysis, results and conclusions presented in this report should be interpreted on the basis of the NO_x retrofit experience reported to date. Regardless of the commercialization status of controls, site-specific analyses are recommended to ascertain whether the emission levels, percent NO_x reductions, and costs cited in this report can be achieved on a long-term basis by a given site. Site-specific factors that influence NO_x reductions and control targets, such as important boiler design, operation, and fuel characteristics, are highlighted and general trends discussed.

In the Northeast, approximately 40 percent of the total annual NO_x emissions are from stationary sources and the remaining 60 percent are from mobile sources. NO_x emissions adversely affect human health and the environment. NO_x emissions chemically react with other pollutants to form ozone; nitrogen dioxide; gaseous and particulate acids, including nitric acid; and other pollutants. In 1987, NO_x emissions from all sources in the NESCAUM region totaled approximately 1.6 million tons. Utility NO_x emissions in the NESCAUM region represent over 20 percent of the inventory, totalling about 380,000 tons. Figure 1-1 illustrates the contribution of major boiler design types to the total NO_x emitted in 1987 from all utility boilers in the NESCAUM region. The data show that the major emitters of NO_x emissions are wall and opposed gas-/oil-fired boilers, which contribute 24 percent of the total emissions, followed by wall and opposed pulverized coal (PC)-fired (21 percent), tangential oil-/gas-fired (20 percent), wet-bottom boilers (nearly 18 percent), and tangential PC-fired boilers (14 percent). Although fewer in number, coal-fired slagging furnaces, which include cyclone and wet-bottom wall-fired boilers, contribute nearly as much as other major design types. The combined NO_x output of other boiler designs, including stokers and small oil-/gas-fired units, contributes only about 3 percent of the total NO_x emitted by utilities in the region.

In examining the region by capacity in MWe, PC-fired boilers account for about 20 percent of the total capacity in the NESCAUM region. Among PC units, tangential- or corner-fired designs account for about 43 percent of the capacity, followed by opposed-firing (27 percent), and single wall-firing, including vertical or down-fired units, (30 percent). Many of the combustion controls developed for wall-fired boilers are equally applicable to single or opposed wall-fired boilers.

The two major routes of NO_x formation are the high-temperature oxidation of nitrogen in the combustion air (thermal NO_x), and the conversion of fuel-bound nitrogen (fuel NO_x). When fuel is burned in utility boilers, both thermal and fuel NO_x are a function of fuel properties and

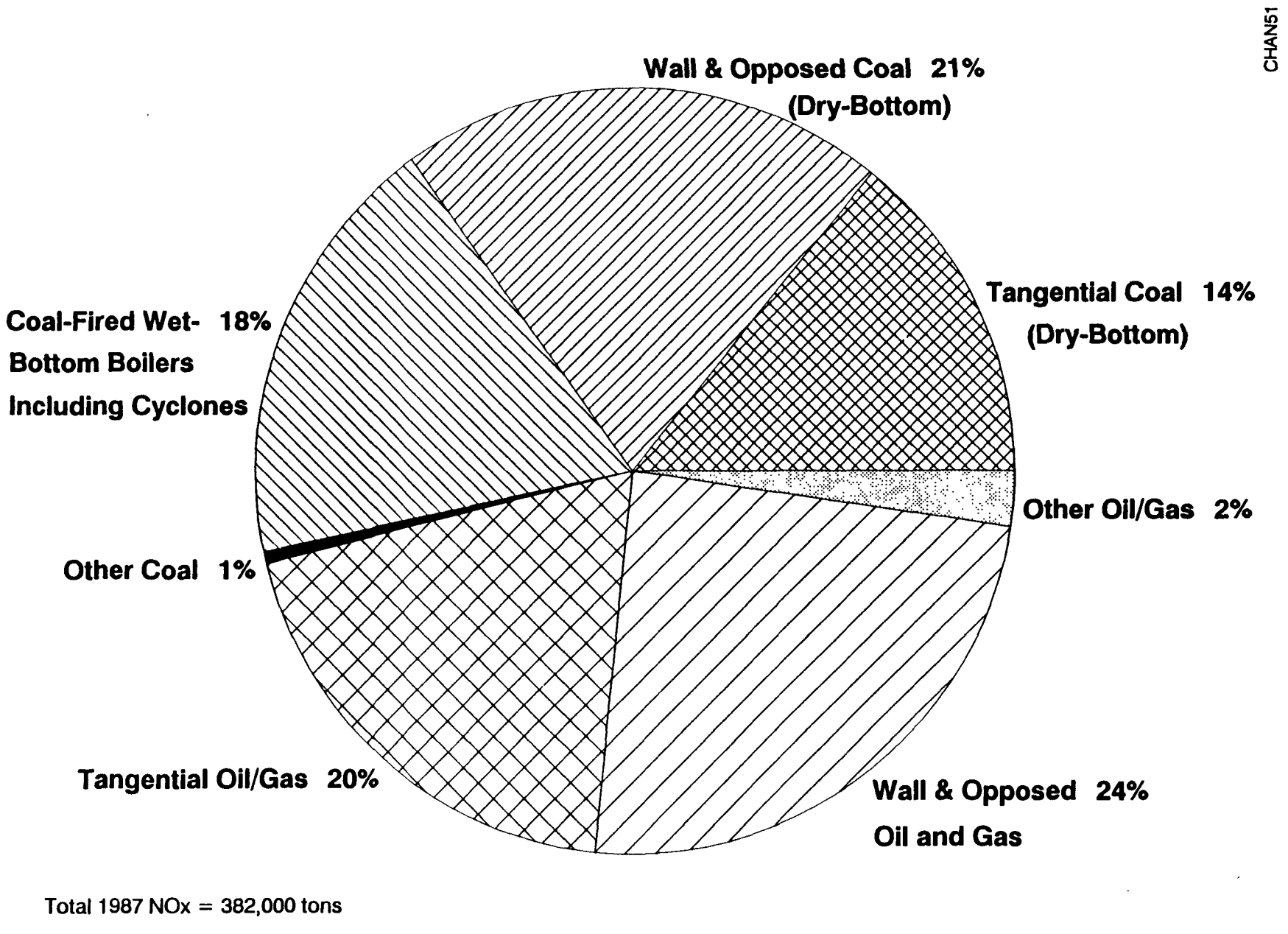

Figure 1-1. Contribution of boiler/fuel types to the total utility NO_x inventory

many boiler design and operating variables. Among the most influential variables are the fuel nitrogen content, the excess air, the heat release rate per unit of waterwall area in the burner zone, the amount of air preheat, and the burner spacing and stoichiometry. When pulverized coal is burned, the fuel ratio (FR, fixed carbon divided by volatile matter) and oxygen/fuel nitrogen ratio also influence the uncontrolled emissions and NO_x levels achievable with combustion controls. Typically, the more volatile the coal (lower FR), the greater the potential for large NO_x reductions and lower controlled levels. Therefore, high-volatile bituminous coals and western subbituminous coals will show greater reduction efficiencies and lower NO_x levels with combustion modifications. This is due in part to the ability to apply greater degrees of combustion control without incurring unacceptable losses in combustion and thermal efficiencies. Similarly, low-nitrogen fuels such as light oils and clean-burning natural gas, offer the potential for the lowest NO_x levels because control is limited to reducing thermal-NO_x.

Combustion modification technologies are the principal methods for controlling NO_x from existing and new utility boilers. The retrofit feasibility, NO_x reduction performance, and costs of combustion controls are largely influenced by boiler design and operating characteristics such as the firing configuration, the furnace size and heat release rate, the type of fuel used, the boiler capacity factor, and the condition of existing equipment. Many of these factors vary with the age of the unit. Flue gas treatment (FGT) controls, including catalytic and noncatalytic processes, can provide additional NO_x reductions from combustion-controlled levels or can be used without combustion modifications. The retrofit feasibility and cost of FGT controls are often influenced by the fuel type, the capacity factor, the load dispatch profile, and several site-specific factors, including site access and space availability.

Table 1-1 summarizes NO_x reduction performance, application, and anticipated equipment modifications for retrofit NO_x combustion modification controls for pre-New Source Performance Standard (NSPS) and post-NSPS coal-fired utility boilers. The achievable percent NO_x reductions listed in the table reflect performance levels reported in the literature. These reduction efficiencies were applied to baseline NO_x ranges from the various boiler designs. Larger percent NO_x reductions generally apply to boilers with higher baseline NO_x levels, plants burning coals that have low-NO_x properties with combustion staging (e.g., high volatile content), and short-term duration tests under favorable boiler operating conditions. Table 1-1 shows that overfire air (OFA), low-NO_x burner (LNB), LNB+OFA, and reburning are candidate combustion modification controls for retrofitting existing coal-fired boilers. The bulk of the retrofit experience to date is limited to LNB only, however. For wall-fired boilers (both single wall- and opposed-fired units), LNBs are generally installed without OFA because the retrofit of OFA involves added expenses and the potential for adverse impacts on the operation and efficiency of the boiler. Current domestic experience with LNB+OFA for wall-fired PC boilers is minimal. Although few foreign installations have reported attractive short-term results, one ongoing demonstration in the U.S. indicates minimal added benefit of OFA to overall NO_x reduction accompanied by a significant fuel penalty. Whereas combustion efficiency loss is likely with LNB alone, a larger efficiency loss is a certainty when OFA is used in conjunction with LNB.

For tangential boilers, separate OFA (SOFA) is the most effective feature, in terms of NO_x reduction, of advanced tangential firing systems. However, experience with retrofit of LNB with SOFA for tangential coal-fired boilers is currently limited to a few installations with NO_x reduction levels on the order of 40 percent to levels below 0.45 lb/MMBtu, measured on a long-term basis (continuously over a period of 30 days or longer). Natural gas reburning (NGR) is an effective combustion option for all coal-firing boiler types, including cyclones, and can result in 45- to 60-percent NO_x reductions. The technical and economic feasibilities of NGR are currently under study at four full-scale demonstrations sponsored by DOE, GRI, EPRI, and host utilities.

Table 1-1. Combustion controls for coal-fired utility boilers

Control Technology	Achievable Percent NO_x Reduction and Controlled NO_x Levels (lb/MMBtu)[a]		Applicable Boiler Designs	Anticipated Equipment Modifications and System Upgrades
	Pre-NSPS	Post-NSPS[b]		
OFA or advanced overfire air (AOFA)	15 to 30 (0.40 - 0.50) T 15 to 25 (0.70 - 0.80) W	15 to 25 (0.40 - 0.50) W	Some wall- and T-fired dry bottom boilers with large furnaces	Installation of OFA ducting and ports with waterwall panel modification. Addition of OFA airflow dampers for improved distribution. Installation of curtain air for some designs. Asbestos removal for older units. Continuous emission monitoring system (CEM) and OFA damper control.
LNB (T-fired units equipped with CCOFA)	25 to 30 (0.40 - 0.45) T 35 to 55 (0.45 - 0.60) W	20 to 30 (0.40 - 0.45) W	Most wall- and T-fired boilers, except slagging units	Installation of new burners and scanners. Replacement of burner zone tubing panels in some units. Burner/pulverizer control system upgrade. Replacement of coal piping, hangers, valves, igniters, viewports. Structural modifications and platforms. Windbox modifications and mill upgrades. CEM system retrofit.
LNB+OFA (AOFA for W-boilers; SOFA for T-units)	30 to 50 (0.30 - 0.45) T 40 to 60 (0.35 - 0.55) W	35 to 45 (0.35 - 0.40) W	Some wall- and T-fired boilers exclusive of high heat release rate units	All equipment upgrades and replacements cited above, plus: replacement of (T) or modification (W) of windbox. Replacement of combustion air control system. Fan and pulverizer modifications. Installation of OFA ports and waterwall panel modifications.
Reburning with natural gas (NGR) or coal. (requires OFA for all retrofits)[c]	45 to 60 (0.50 - 0.70) C,S 40 to 60 (0.25 - 0.35) T 45 to 60 (0.40 - 0.50) W	40 to 55 (0.25 - 0.35) W	All boilers, but technology targeted primarily for cyclone (C) and slagging (S) units	Installation of reburning burners and OFA ports. Replacement of tube wall panels. Piping ductwork to reburn burners and OFA ports. Burner/combustion control system. Gas fuel substation for NGR or pulverizer installation for coal reburn on cyclones. FGR ducting, fan, and CEM system.

W = Wall-and opposed- fired boilers, T = Tangential (corner)-fired boilers;
C = Cyclone boilers, S = boilers with high heat release slagging furnaces.
[a]Controlled levels are based on estimated reduction performance and weighted average baseline levels reported in Table 3-4.
[b]Only one boiler in the NESCAUM region is listed as a post-NSPS-design unit. Controlled emission levels are from current baseline of 0.55 lb/MMBtu for the opposed wall-fired boiler.
[c]Reburning is offered by major boiler manufacturers in Japan and the United States, but no commercial experience exists in the United States. Several demonstration and validation projects are ongoing and reporting successful results and pointing to the commercial viability of the technology.

Reburning using pulverized coal is also under study for cyclone boilers, and shows initially promising results. These reburn technologies offer the potential for use in commercial applications in the near future.

Ranges in control efficiency and NO_x control levels, rather than specific numbers, are given for each of the retrofit cases evaluated in this study. The ranges indicate several important points that require explanation. First, there is a degree of uncertainty in the actual performance that can be obtained at each power plant site. This uncertainty can be narrowed only with detailed analyses of several site-specific factors. Therefore, when considering a broad family of boilers, it is more appropriate to provide a range in performance rather than a fixed value. Second, these results are based on performances reported to date for several retrofits. Data obtained from more than one retrofit also indicate a range in performance indicative of variations in actual NO_x reduction efficiency and control level that can be achieved from site to site. Third, lower NO_x reduction efficiencies and higher NO_x emission levels reflect results that can be anticipated under more trying control conditions. These conditions include high initial uncontrolled NO_x, low coal fineness, combustion of low-volatile eastern coal, operational difficulties, and compliance with emissions averaged over a long-term period (e.g., 30 days) to account for routine variations in key operational parameters that affect NO_x. Conversely, the higher reduction efficiency and lowest NO_x reflect the best performance reported to date, excluding results of some retrofits that are not considered commercial for widespread application in NESCAUM and exclusive of selected vendor claims. As discussed later, this higher performance is generally associated with volatile coals and short-term results obtained at selected boiler loads under well-controlled conditions, and over a period of time not exceeding a few hours of continuous monitoring.

The NESCAUM population of PC-fired boilers includes only one post-NSPS Subpart Da unit whose reported level of NO_x is 0.55 lb/MMBtu. The retrofit of newer vintage LNBs without OFA ports on this unit is projected to, at best, reduce NO_x to 0.40 to 0.45 lb/MMBtu, based on limited data collected with two retrofits on a short-term basis. Coupled with OFA, controlled NO_x levels are estimated to be slightly lower. However, no supporting documentation on similar LNB+OFA retrofits is available.

Approximately 50 percent of the current pre-NSPS dry-bottom wall-fired capacity in NESCAUM has an average NO_x level of about 0.95 lb/MMBtu. The retrofit of LNB to most of these boilers will reduce the average NO_x level to a range of about 0.45 to 0.60 lb/MMBtu. This level of control corresponds to a reduction of 35 to 55 percent (rounded to the nearest 5 percent) from the average baseline level and is supported by results from several retrofits monitored on short- and long-term bases. Lower emitting units will show lower reduction efficiencies because combustion modification is limited to a minimum level of NO_x that can be achieved at a given site without incurring major operational and energy penalties. For those wall-fired boilers that can be retrofitted and operated with OFA in addition to LNB, controlled NO_x levels are estimated to range from 0.35 to 0.55 lb/MMBtu (40- to 65-percent reduction). Again, the higher NO_x level (0.55 lb/MMBtu) is representative of retrofit cases and operating conditions that are considered more prevalent in the NESCAUM region (e.g., low-volatile coals and pre-NSPS). A much smaller number of utility boilers are considered retrofittable with OFA or advanced overfire air (AOFA) without significantly affecting efficiency, operation, and reliability. This is because many of these boilers have small pre-NSPS furnaces that do not provide the access or gas residence time needed for safe and effective operation. OFA, alone or in combination with LNB, is only as effective as the degree of air staging used. This is limited by the adverse effects of excessive staging on waterwall slagging corrosion and loss on ignition (LOI) that are considered more likely with compact furnace designs burning high-sulfur coals.

These estimates of NO_x reduction, together with estimates of retrofit potential to the existing population, can be used to estimate the total NO_x reduction potential for these technologies on a systemwide basis. For example, widespread retrofit of LNB is estimated to result in NO_x reductions between 29,000 and 42,000 tons/yr with a target coal-fired retrofit capacity of about 5,800 MWe. Application of other technologies currently under development and demonstration on cyclone and wet-bottom boilers, such as reburning, can achieve additional systemwide NO_x reductions. Consider, for example, the combination of 5,800 MWe of LNB retrofit on existing dry-bottom units with 1,200 MWe of reburn retrofit on existing wet-bottom units (including cyclones). This combination is estimated to remove about 50,000 to 70,000 tons/yr of NO_x from current NESCAUM-wide coal-fired levels of about 200,000 tons/yr. These estimates are calculated based on broad assumptions of retrofit feasibility using estimates of current emission levels and projected NO_x reduction efficiencies. Because of the uncertainties involved, actual reductions may be higher or lower.

Combustion modifications in full-scale, oil-, and gas-fired utility boilers can result in significant NO_x reductions. Ninety percent reductions have been achieved from very high uncontrolled levels on some units in California. Table 1-2 summarizes the performance and hardware modifications for applicable NO_x combustion controls for oil-/gas-fired boilers in the NESCAUM region. Combustion modification controls for oil-/gas-fired boilers have been implemented since the early 1970s, primarily in California. Past retrofit efforts in California can provide a wealth of technology and retrofit experience that is directly applicable to the NESCAUM oil-/gas-fired units. Although NO_x reduction successes similar to those of the California utilities cannot be guaranteed (fuel oil properties are different, for example), significant reductions in NO_x are possible. Important fuel differences include the use of high-grade low-nitrogen fuel oil in California, and a heavier reliance on natural gas. In NESCAUM, heavier crudes with higher nitrogen, ash, and sulfur content are used, and there is a greater reliance on fuel oil rather than natural gas.

Commercially available controls for oil-/gas-fired boilers include burners out of service (BOOS), flue gas recirculation (FGR), LNB, and a combination of these. Reburning for these boiler types has not received wide scrutiny, and is not considered either commercially available or sufficiently demonstrated to be a near-term option. As stated, experience with these combustion controls is substantial considering existing retrofits in California, Texas, and New York. A combination of BOOS+FGR is anticipated to reduce NO_x levels to at least 0.30 lb/MMBtu, for wall-fired units, and 0.20 lb/MMBtu, for tangential units, from average baseline levels of 0.45 lb/MMBtu and 0.30 lb/MMBtu for all wall and tangential units, respectively. Lower NO_x levels are possible, depending on the type of fuel or fuel mix used and the success of recently introduced LNB technology.

The 1987 NO_x emission inventory from oil-/gas-fired utility boilers was 176,000 tons/yr. To estimate NESCAUM-wide NO_x reductions from these boilers using combustion controls, two control scenarios were evaluated. The first considered an NO_x limit of 0.3 lb/MMBtu for all dry-bottom tangential-, wall-, and opposed-fired boilers. NO_x emissions would be reduced by 30,000 tons/yr under this scenario. NO_x reductions would occur primarily from wall-fired boilers whose baseline emissions currently exceed 0.3 lb/MMBtu. A more stringent control limit of 0.2 lb/MMBtu for all dry-bottom units, regardless of fuel mix, would result in NO_x reductions of 50,000 to 60,000 tons/yr throughout NESCAUM.

Commercially available technologies for the control of NO_x after it is formed in the combustion process are currently limited to the selective noncatalytic reduction (SNCR) and SCR. Both of these processes have seen very limited application in the United States for utility boilers.

Table 1-2. Combustion controls for oil- and gas-fired utility boilers

Control Technology	Achievable Percent NO_x Reduction and Controlled NO_x Levels (lb/MMBtu)[a]		Applicable Boiler Designs	Anticipated Equipment Modifications and System Upgrades
	Pre-NSPS	Post-NSPS		
BOOS or Biased Firing	30 to 35 (0.30 - 0.35) W 15 to 20 (0 20 - 0.25) T	25 to 35 (0.25 - 0.30) W 25 to 40 (0.20 - 0.25) T	Most wall- and T-fired boilers. Several BOOS patterns are possible. Engineering testing needed	Windbox upgrade for effective air management. Fuel control system upgrade. Installation of O_2/CO trim system. Possible modification to superheater and steam attemperation
Windbox FGR	25 to 40 (0 25 - 0.35) W 25 to 40 (0.20 - 0 25) T	20 to 30 (0.25 - 0.30) W 20 to 30 (0.15 - 0.20) T	Most wall- and T-fired boilers. FGR rates most effective up to 15% depending on fuel and O_2.	Installation of FGR fan, ducting, and dampers. Windbox modifications. Removal of asbestos in some older plants. replacement of flame scanners. Installation of O_2 monitoring for windbox. Boiler control and O_2/CO trim.
LNB	40 to 50 (0.25 - 0.30) W 25 to 50 (0.15 - 0.25) T	30 to 40 (0.20 - 0.25) W 20 to 40 (0.15 - 0.20) T	Most wall- and T-fired boilers. Installation may be needed for improved flame stability with other controls	Modification of windbox for compartmentalized combustion air distribution. Burner replacement and possible additional burner parts and waterwall modifications. Installation of O_2/CO trim system. Fuel supply and valving, and burner control system upgrade.
BOOS+FGR	40 to 50 (0.25 - 0.30) W 30 to 50 (0 15 - 0.20) T	40 to 50 (0.15 - 0.20) W 30 to 40 (0.15 - 0.20) T	Most wall- and T-fired boilers. See above for combination of BOOS and FGR	Combination of BOOS and FGR retrofit equipment requirements and upgrades.
BOOS (or OFA) +FGR+LNB	60 to 80 (0.10 - 0.20) W 40 to 70 (0.10 - 0.20) T	45 to 70 (0.10 - 0.20) W 40 to 60 (0.10 - 0.15) T	Most wall- and T-fired boilers with possible exception of high heat release furnaces	Combination of BOOS, FGR, and LNB equipment modifications and upgrades. Possible requirement for fan upgrades and asbestos removal for older plants.
Reburning (NGR)[b]	50 to 60 (0.20 - 0.25) W 50 to 60 (0.15 - 0 20) T 50 to 60 (0.25 - 0.30) C	30 to 50 (0.20 - 0.25) W 30 to 50 (0.15 - 0 20) T	Most attractive retrofits include fuel conversion (coal to oil/gas) units because of larger firebox	Installation of reburning fuel and overfire air ports, Replacement of furnace waterwall sections. Possible modifications to superheater tube bank and attemperation. Upgrading of structural support and compartmentalized windbox. Installation of O_2/CO trim and boiler control system. Possible extension of furnace height.

W = Wall-and opposed- fired boilers; T = Tangential (corner)-fired boiler; C = Cyclone-fired boiler.

[a]Percent reductions are determined from reported controlled NO_x levels (See Appendix D) and average baseline emissions in NESCAUM.

[b]NGR experience for oil- and gas-fired units is minimal abroad and nonexistent in the United States. Estimates of control efficiency are speculative.

However, SCR is being used extensively in Japan and Germany with reported successes with all fuels; and SNCR claims 44 boiler retrofits worldwide on all fuels, as of this writing. Most SCR applications to PC-fired boilers must consider the sulfur content of coal to minimize SO_2 to SO_3 conversion over the catalyst. This is especially important for hot-side applications of SCR systems. Recent applications of SCR catalysts in Europe and Japan have been on high-sulfur coals, with the catalysts installed upstream of flyash and sulfur scrubbing (hot-side), indicative of advances in catalyst formulations that minimize SO_2 to SO_3 conversion while resisting abrasion and plugging. The SCR process has been investigated for coal-fired boiler retrofits in a few pilot- and full-scale utility boiler programs sponsored by the Electric Power Research Institute (EPRI), the U.S. Environmental Protection Agency (EPA), and selected utilities.

The SNCR process has been used with moderate to high success primarily on smaller industrial combustion sources, fluidized-bed combustors in California, and two PC-fired boilers also in California. There are also ongoing demonstrations at utilities in the states of New York, Colorado, and California. Renewed regulatory efforts to attain ozone air quality standards in southern California's Los Angeles Basin are leading to several demonstrations of both SNCR and SCR commercial equipment. For example, Southern California Edison (SCE) has planned a total of 5,000 MWe retrofits with SNCR (urea-based). Many of these retrofits are already in place. Several Japanese SCR vendors are offering this technology in the U.S. SCR retrofit projects have begun for SCE and some U.S. gas turbine cogeneration facilities. At least four vendors are offering urea- or ammonia-based SNCR processes for combustion sources including utility boilers.

Table 1-3 lists estimates of NO_x reduction and achievable NO_x levels with FGT controls on NESCAUM boilers. These estimates are based on retrofits on currently uncontrolled boilers (Case 1) and on boilers already controlled with combustion modifications (Case 2). Control efficiencies for SNCR range between 25 and 50 percent. For SCR, control efficiencies are estimated to range between 60 and 85 percent depending on application, fuel, and inlet NO_x concentration. Generally, lower performance is anticipated with lower inlet concentration, and, in the case of SCR, when the catalyst is installed in a more severe flue gas environment.

NO_x levels achievable with the application of SNCR on combustion-controlled coal-fired boilers range from 0.35 to 0.45 lb/MMBtu, for wall-fired units equipped with LNB, and from 0.25 to 0.35 lb/MMBtu, for T-fired boilers also equipped with LNB + close-coupled overfire air (CCOFA). For oil-/gas-fired boilers, corresponding NO_x levels range from 0.20 to 0.25 lb/MMBtu, for wall-fired units, and from 0.10 to 0.15 lb/MMBtu, for T-fired boilers. NO_x levels achievable with the application of hot-side SCR to combustion-controlled boilers are as low as 0.10 to 0.20 lb/MMBtu, for coal units, and 0.05 to 0.10 lb/MMBtu, for oil-/gas-fired boilers. Limited application of SNCR technology could result in an additional 8,000 tons of NO_x reductions per year from coal units already equipped with LNB controls, and 14,000 tons/yr from oil-/gas-fired units equipped with TSC (BOOS or OFA) controls plus FGR capable of reducing NO_x to 0.25 lb/MMBtu. Limited application of SCR technology could result in an additional 23,000 tons/yr of NO_x reduction from LNB-controlled coal units, and 25,000 tons/yr from combustion-controlled oil-/gas-fired units. These numbers are based on limited FGT retrofit on boilers that use fuels with a sulfur content of less than 1.5 percent and an estimate of 50-percent applicability of FGT controls to this target capacity.

The costs of controlling NO_x emissions presented in this report are based on cost data reported in the literature for similar retrofit cases or, when available, on estimates obtained directly from technology vendors and users. However, actual retrofit costs will depend on several site-specific factors, and a given technology may not be relevant for all boilers. Therefore, the costs presented should not be interpreted as applicable to any specific power plant within the NESCAUM

Table 1-3. Flue gas treatment controls

Technology	Achievable Percent NO_x Reduction and Controlled NO_x Levels (lb/MMBtu)		Applicable Boiler Designs	Anticipated Equipment Modifications and System Upgrades
	PC-fired Boilers[a]	Oil- and Gas-fired Boilers[b]		
SNCR (urea or NH_3 based)	Case 1: 30 to 50 (0.50 - 0.65) W 30 to 50 (0.30 - 0.40) T Case 2: 25 to 40 (0.35 - 0.45) W 25 to 40 (0.25 - 0.35) T	Case 1: 35 to 50 (0.25 - 0.30) W 35 to 50 (0.15 - 0.20) T Case 2: 25 to 40 (0.20 - 0.25) W 25 to 40 (0.10 - 0.15) T	Applicable to most boiler designs. Application is more likely on boilers burning low sulfur fuel and noncycling units	Detailed mapping of flue gas needed. Installation of reagent storage, distribution, feedrate control, and injection grids. Installation of CEM and ammonia monitoring system. Possible modification to tube banks and upgrade of air heater washing.
SCR (hot-side retrofit)	Case 1: 70 to 80 (0.20 - 0.30) W 70 to 80 (0.15 - 0.20) T Case 2: 70 to 80 (0.15 - 0.20) W 70 to 80 (0.10 - 0.15) T	Case 1: 70 to 80 (0.10 - 0.15) W 70 to 80 (0.05 - 0.10) T Case 2: 60 to 80 (0.05 - 0.10) W 60 to 80 (0.05 - 0.10) T	Applicable to most boiler design. Application more likely on boilers burning low-sulfur and low-fuel and baseline units.	Reactor installation upstream of air heater with economizer bypass for temperature control. Upgrade fans. Installation of NH_3 storage, distribution, and feedrate control. Installation of CEM system. Cold end equipment relocation possible including building structure and stack
SCR (cold-side retrofit)	Case 1: 75 to 85 (0.15 - 0.25) W 75 to 85 (0.10 - 0.15) T Case 2: 75 to 85 (0.10 - 0.15) W 75 to 85 (0.05 - 0.10) T	NA[c]	Applicable to most boilers including high-sulfur high-ash burning units if equipped with FGD system.	Reactor installation upstream of ID fan and stack. Fans upgrade. Installation of stack gas reheat and heat recovery sections. Installation of reagent storage, distribution, and control systems. Installation of CEM system.

[a] NO_x reductions from pre-NSPS boilers average uncontrolled emissions of 0.95 lb/MMBtu for wall-fired units and 0.60 lb/MMBtu for T-fired units (Case 1) and LNB-controlled levels of 0.60 lb/MMBtu for wall-fired boilers and 0.45 lb/MMBtu for T-fired boilers (Case 2).

[b] NO_x reductions from all listed gas- and oil-fired boilers (pre- and post-NSPS) with uncontrolled NO_x levels of 0.45 lb/MMBtu for wall-fired boilers and 0.28 lb/MMBtu for T-fired boilers (Case 1), and BOOS+FGR - controlled levels of 0.30 lb/MMBtu for wall-fired boilers and 0.20 lb/MMBtu for T-fired boilers (Case 2).

[c] NA = Not applicable All SCR systems for gas- and oil- fired boilers will use pre-air heater reactor installation.

utility boiler population. By evaluating several cases based on boiler size, age, capacity factor, and NO_x reduction efficiency, ranges in NO_x control costs were developed that encompass some of the uncertainties due to site-specific factors. To develop actual cost estimates for specific power plants, it is necessary to perform a detailed analysis of the type and condition of the existing equipment, its layout, the fuel type, and the boiler operating characteristics.

A simplified cost estimating procedure was developed is this study. The procedure contains all the principal cost elements of the EPA's Integrated Air Pollution Control System (IAPCS). The IAPCS was developed by the EPA's Air and Energy Engineering Research Laboratory (AEERL) to estimate the costs and performance of emission controls for coal-fired utility boilers. Originally patterned after the Tennessee Valley Authority cost model, it now incorporates many of EPRI's Technical Assessment Guide cost elements and procedures are needed to evaluate the capital and levelized busbar costs and cost effectiveness of power plant equipment, including air pollution control retrofit equipment. Estimates of total capital requirement (TCR) were annualized over the remaining life of the boiler using a capital recovery factor based on a 10-percent discount rate. The annualized capital was then added to the estimate of annual operation and maintenance (O&M) costs to calculate the total busbar cost of the control. All costs are on the basis of constant dollars using 1st quarter 1991 as the base year.

Thirty-six boiler NO_x control retrofit cases were evaluated to determine the costs and cost effectiveness of various boiler-control combinations. For each of these test cases, parametric variations in boiler capacity, age, capacity factor, and NO_x control efficiency were evaluated to determine the effects of these variables on the overall costs. The range in boiler age and capacity factor was based on the current population profile in the NESCAUM region. Estimates of NOx reductions for cost-effectiveness calculations were based on average baseline emission factors and average controlled levels shown in Table 1-1 for each boiler class and control technology. Costs for FGT controls (SNCR and SCR) were evaluated based on application on both the uncontrolled boilers and combustion-controlled boilers.

Table 1-4 summarizes the economic data for 18 control retrofit cases for coal-fired boilers investigated in this study. This table uses a standard size boiler (200 MWe) for comparing the cost of control options. The complete data from these cost scenarios are described in more detail in the full text of the report and in Appendices F and G. The results for wall-fired PC units indicate that the total capital requirements for combustion controls range from $20 to $42/kW. The cost effectiveness ranges from a low of $160/ton, for LNB, to $1,200/ton, for NGR, depending on the degree of NO_x control required. Also, higher cost effectiveness is estimated for tangential units because of lower uncontrolled levels from these boiler types. Note that these capital costs are specific to a given boiler size. The costs would be lower for larger size boilers and higher for smaller size boilers, as discussed in Section 6 of this report.

The cost of reducing NO_x from wall-fired PC boilers by 35 to 55 percent with current LNB technology is estimated to range between $160/ton and $450/ton of NO_x removed. The retrofit of LNB, or LNB+CCOFA, for T-firing is estimated to result in the least cost per ton of NO_x reduced. The cost per ton of NO_x removed of added OFA with LNB is anticipated to be higher because installation of OFA requires significant added capital, results in greater fuel penalty and, for wall-fired units, adds little additional NO_x reduction.

Although SNCR costs are estimated to be cost competitive with combustion modifications, a higher degree of uncertainty exists because of limited full-scale experience on the long-term operational impact of reagent-based FGT controls. Similarly, the cost of reburning using natural gas is estimated to be well below $1,000/ton of NO_x removed when applied to high-NO_x-emitting

Table 1-4. Summary of NO_x control costs for coal-fired utility boilers (1st Qtr $1991)

Boiler Firing Type	NO_x Control Technology	Uncontrolled NO_x Level[a] (lb/MMBtu)	Estimated Range in NO_x Control Levels[b] (lb/MMBtu)	Control Costs		
				Total Capital Requirement ($/kW)	Levelized Busbar (Mills/kWh)	Cost Effectiveness ($/ton)
Wall-firing	OFA	0.95	0.70 - 0.80	20	0.49 - 0.75	410 - 1,100
	LNB	0.95	0.45 - 0.60	20	0.43 - 0.69	160 - 450
	LNB+OFA	0.95	0.35 - 0.55	40	0.88 - 1.7	270 - 800
	NGR	0.95	0.40 - 0.50	42	2.1 - 2.9	710 - 1,200
	SNCR on uncontrolled boilers	0.95	0.50 - 0.65	18	1.9 - 3.0	590 - 1,100
	SNCR on LNB-controlled boilers	0.60	0.35 - 0.45	18	1.0 - 1.4	760 - 1,680
	SCR on uncontrolled boilers[c]	0.95	0.15 - 0.25	192	7.0 - 12	1,650 - 3,220
	SCR on LNB-controlled boilers[c]	0 60	0.10 - 0.15	192	6.9 - 12	2,600 - 4,970
	SCR on LNB-controlled boilers[c,d]	0.60	0.15 - 0.20	148	5.1 - 9.1	2,100 - 4,250

These costs were developed for the following conditions:

- 200 MWe for all boilers
- Capacity factors = 40 to 82 percent for wall and tangential units, 55 to 83 percent for cyclones (see Section 6 for effect of capacity on these costs)
- Boiler age 20 to 40 years for wall and tangential units, 27 years for cyclones

[a]See Table 3-4 for average baseline levels in the NESCAUM Region. Only pre-NSPS units are considered.

[b]See Tables 1-1 and 1-3, Section 4 and Appendix D for estimated range in controlled NO_x levels.

[c]Cost of SCR retrofit based on catalyst unit cost of $660/ft^3 and life of 4 years. Effects of other catalyst cost and life are discussed in Section 6.

[d]SCR installed at the economizer outlet (hot-side case). All other SCR cases are for catalyst reactor installed downstream of particulate and FGD controls (cold-side)

Table 1-4. Summary of NO_x control costs for coal-fired utility boilers (1st Qtr $1991) (concluded)

Boiler Firing Type	NO_x Control Technology	Uncontrolled NO_x Level[a] (lb/MMBtu)	Estimated Range in NO_x Control Levels[b] (lb/MMBtu)	Control Costs		
				Total Capital Requirement ($/kW)	Levelized Busbar (Mills/kWh)	Cost Effectiveness ($/ton)
Tangential-firing	LNB w/CCOFA	0.60	0.40 - 0.45	24	0.52 - 1.0	490 - 1,270
	LNB+SOFA	0.60	0.30 - 0.45	30	0.67 - 1.3	420 - 1,590
	NGR	0.60	0.25 - 0.35	42	2.1 - 2.9	1,110 - 2,180
	SNCR on uncontrolled boilers	0.60	0.30 - 0.40	18	1.0 - 1.4	630 - 1,260
	SNCR on LNB-controlled boilers	0.45	0.25 - 0.35	18	0.84 - 1.2	790 - 2,200
	SCR on uncontrolled boilers[c]	0.60	0.10 - 0.15	192	7.0 - 12	2,600 - 4,970
	SCR on LNB-controlled boilers[c]	0.45	0.05 - 0.10	192	6.9 - 12	3,200 - 6,370
	SCR on LNB-controlled boilers[c,d]	0.45	0.10 - 0.15	148	5.1 - 9.0	2,700 - 5,600
Cyclones	NGR	1.28	0.50 - 0.70	42	2.1 - 2.5	500 - 800

These costs were developed for the following conditions:

- 200 MWe for all boilers
- Capacity factors = 40 to 82 percent for wall and tangential units, 55 to 83 percent for cyclones (see Section 6 for effect of capacity on these costs)
- Boiler age 20 to 40 years for wall and tangential units, 27 years for cyclones

[a]See Table 3-4 for average baseline levels in the NESCAUM Region. Only pre-NSPS units are considered.

[b]See Tables 1-1 and 1-3, Section 4 and Appendix D for estimated range in controlled NO_x levels.

[c]Cost of SCR retrofit based on catalyst unit cost of $660/ft^3 and life of 4 years. Effects of other catalyst cost and life are discussed in Section 6.

[d]SCR installed at the economizer outlet (hot-side case). All other SCR cases are for catalyst reactor installed downstream of particulate and FGD controls (cold-side).

cyclone units. The low cost per ton of NO_x removed is due principally to the significant NO_x reduction potential for these units. Uncertainties in costs for reburning are associated with the limited data on long-term operational impacts and ability to secure long-term contracts for natural gas in the NESCAUM region. Because natural gas supply to industry is more plentiful during summer months, when ambient ozone concentrations are typically at the highest levels, reburning may be a cost effective approach for seasonal NO_x control for some units.

Table 1-5 lists cost estimates for retrofit NO_x controls on oil-/gas-fired boilers. The cost of combustion modifications varies from as low as $230/ton to about $5,000/ton. The level of NO_x control that can be achieved with these investments will depend on many factors that are difficult to gauge without a detailed site-specific and fuel evaluation. The lowest cost per ton of NO_x reduced is associated with the implementation of BOOS, which has minimal capital requirement and permits significant NO_x reductions depending on the type of fuel burned, the initial uncontrolled NO_x, and the boiler's flexibility in meeting load demand with a reduced number of burners in service. Several OFA+FGR+BOOS retrofits have taken place in Southern California. Additional combustion optimization is ongoing to maximize NO_x reduction with LNB retrofits and other adjustments. The total capital requirements of these control combinations can be significant as reported by Southern California Edison (SCE) because of the extent of modification required and added operational control. The retrofit of hot-side SCR on oil-/gas-fired boilers can result in emissions as low as 0.05 to 0.08 lb/MMBtu (40 to 60 ppm) when used in combination with LNB+OFA+FGR combination modifications. These levels are more realistic when clean fuels (e.g., natural gas) are burned. The cost effectiveness of this control option, however, can be as high as $15,000/ton when used on combustion-controlled boilers, lower for larger capacity units. Figures 1-2 through 1-5 illustrate the change in cost effectiveness as lower NO_x levels are sought from coal- and oil-/gas-fired boilers. Figures 1-2 through 1-5 illustrate these cost estimates as a function of predicted NO_x levels. Uncertainties in these estimates, and the inherent variability in NO_x control performance and costs from site to site, result in much overlap among control technologies. It is clear that combustion modifications, NGR, and noncatalytic gas treatment offer the lowest cost options for each ton of NO_x reduced.

In conclusion, this study suggests that NO_x emissions from utility boilers in the NESCAUM region can be reduced to levels substantially below levels reported in the late 1980s using a variety of commercially available technologies. These technologies include combustion modifications, burner replacements, and post-combustion technologies such as SNCR and SCR. However, current experience dictates that only selected controls should be considered not only commercially available but also sufficiently demonstrated for immediate retrofit on existing boilers. Regardless of the commercialization status, the retrofit of NO_x controls will require detailed engineering evaluations and site-specific analyses to ensure the safe, reliable, and economical operation of the boiler, while providing the required margin of safety in regulatory compliance.

For PC-fired boilers, domestic LNB retrofit experience is currently the largest of any technology and is expanding. With LNB retrofits the average wall-fired PC unit with an uncontrolled level of 0.95 lb/MMBtu can be projected to meet a range in NO_x from as low as 0.45 to 0.60 lb/MMBtu. Higher-emitting units, and units burning coal with unfavorable properties will likely not be able to meet lowest NO_x reductions projected in this study on either short- or long-term basis. Significant NO_x reduction on oil-/gas-fired units is also projected. Several combustion modification controls are currently commercially available for oil-/gas-fired units, and there is a significant experience base for retrofit consideration on NESCAUM boilers. In fact, some of these controls for oil-/gas-fired units are already in place on some NESCAUM boilers, while others are actively being evaluated. Maximum control potential for these oil-/gas-fired units is difficult to estimate because of the influence of fuel characteristics and other factors. Certainly, a

Table 1-5. Summary of NO_x control costs for oil- and gas-fired utility boilers (1st Qtr $1991)

Boiler Firing Type	NO_x Control Technology	Uncontrolled NO_x Level[a] (lb/MMBtu)	Estimated Range in NO_x Control Levels[b] (lb/MMBtu)	Control Costs		
				Total Capital Requirement ($/kW)	Levelized Busbar (Mills/kWh)	Cost Effectiveness ($/ton)
Wall-firing	BOOS	0.45	0.30 - 0.35	0.61	0.18 - 0.20	230 - 510
	FGR	0.45	0.25 - 0.35	10	0.34 - 0.54	320 - 1,000
	LNB	0.45	0.25 - 0.30	28	0.80 - 1.3	750 - 1,700
	BOOS + FGR	0.45	0.25 - 0.30	11	0.46 - 0.68	440 - 850
	BOOS (OFA) + LNB + FGR	0.45	0.10 - 0.20	55	1.7 - 2.8	900 - 2,600
	SNCR on uncontrolled boilers	0.45	0.25 - 0.30	8.0	0.71 - 0.87	670 - 1,100
	SNCR on BOOS + FGR controlled boilers	0.30	0.20 - 0.25	8.0	0.54 - 0.69	1,000 - 2,600
	SCR on uncontrolled boilers[c]	0.45	0.10 - 0.15	135	4.8 - 7.9	2,600 - 4,900
	SCR on BOOS + FGR controlled boilers[c]	0.30	0.05 - 0.10	135	4.8 - 7.9	3,600 - 7,400

These costs were developed for the following conditions:

- 200 MWe for all boilers (see Section 6 for effect of capacity on these costs)
- Capacity factors = 40 to 65 percent
- Boiler age 15 to 38 years

[a]Average baseline level for all wall- and opposed-fired boilers in NESCAUM. This average combines units listed as pre- and post-NSPS (see Table 3-4) and averages the value to the nearest 0.05 lb/MMBtu.

[b]Combustion-controlled levels are based on minimum and maximum percent NO_x reductions presented in Table 1-2 and Table 4-6 applied to the average baseline NO_x level of 0.45 lb/MMBtu for W-firing and 0.30 lb/MMBtu for T-firing. For FGT controls, the range in controlled NO_x levels is based on estimates presented in Table 1-3.

[c]Cost of SCR based on catalyst life of 6 years.

Table 1-5. Summary of NO_x control costs for oil- and gas-fired utility boilers (1st Qtr $1991) (concluded)

Boiler Firing Type	NO_x Control Technology	Uncontrolled NO_x Level[a] (lb/MMBtu)	Estimated Range in NO_x Control Levels[b] (lb/MMBtu)	Control Costs		
				Total Capital Requirement ($/kW)	Levelized Busbar (Mills/kWh)	Cost Effectiveness ($/ton)
Tangential-firing	BOOS	0.30	0.20 - 0.25	0.61	0.18 - 0.20	340 - 740
	FGR	0.30	0.20 - 0.25	10	0.34 - 0.54	640 - 2,000
	LNB	0.30	0.15 - 0.25	28	0.80 - 1.4	1,000 - 5,100
	BOOS + FGR	0.30	0.15 - 0.20	11	0.46 - 0.68	580 - 1,300
	BOOS (OFA) + LNB + FGR	0.30	0.10 - 0.20	55	1.7 - 2.8	1,600 - 5,200
	SNCR on uncontrolled boilers	0.30	0.15 - 0.20	8.0	0.54 - 0.69	670 - 1,300
	SNCR on LNB-controlled boilers	0.20	0.10 - 0.15	8.0	0.43 - 0.58	800 - 2,200
	SCR on uncontrolled boilers[c]	0.30	0.05 - 0.10	135	4.8 - 7.9	3,600 - 7,400
	SCR on LNB + FGR controlled boilers[c]	0.20	0.05 - 0.10	135	4.8 - 7.9	6,000 - 15,000

These costs were developed for the following conditions:

- 200 MWe for all boilers (see Section 6 for effect of capacity on these costs)
- Capacity factors = 40 to 65 percent
- Boiler age 15 to 38 years

[a]Average baseline level for all wall- and opposed-fired boilers in NESCAUM. This average combines units listed as pre- and post-NSPS (see Table 3-4) and averages the value to the nearest 0.05 lb/MMBtu.

[b]Combustion-controlled levels are based on minimum and maximum percent NO_x reductions presented in Table 1-2 and Table 4-6 applied to the average baseline NO_x level of 0.45 lb/MMBtu for W-firing and 0.30 lb/MMBtu for T-firing. For FGT controls, the range in controlled NO_x levels is based on estimates presented in Table 1-3.

[c]Cost of SCR based on catalyst life of 6 years.

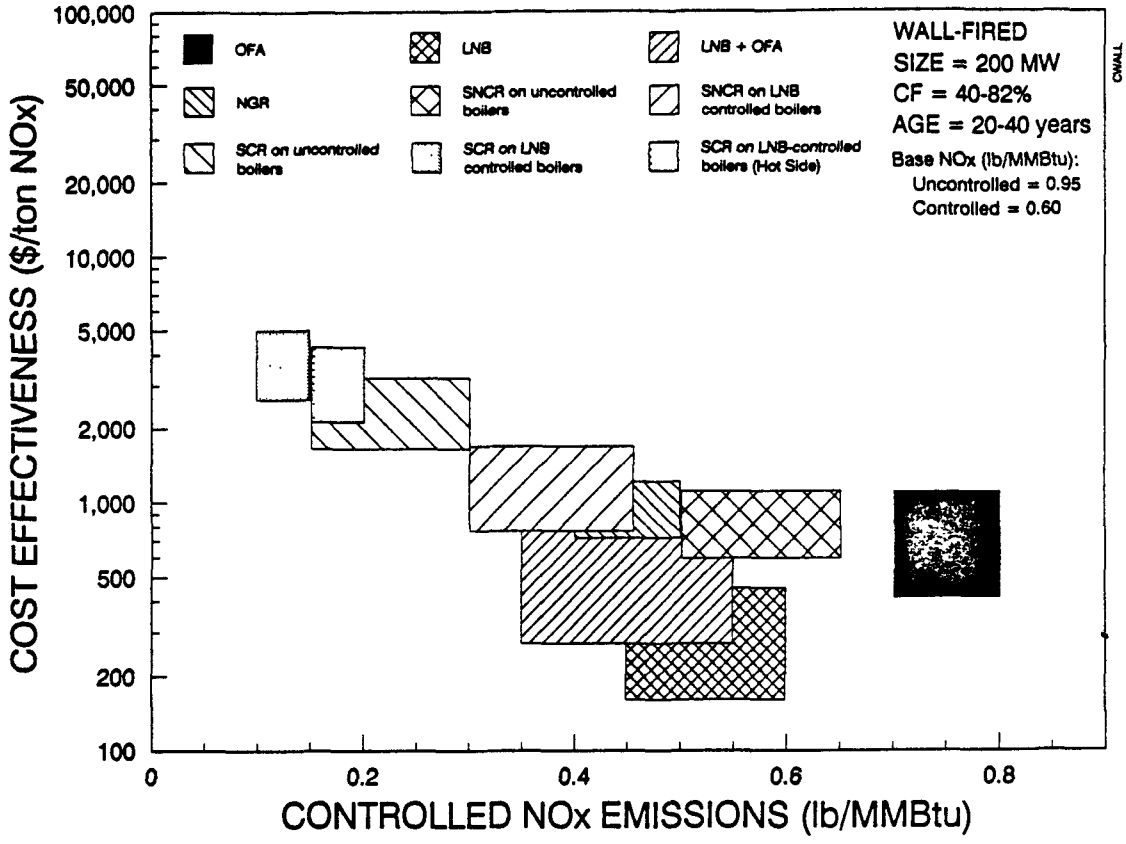

Figure 1-2. NO_x control cost-effectiveness for PC wall-fired utility boilers

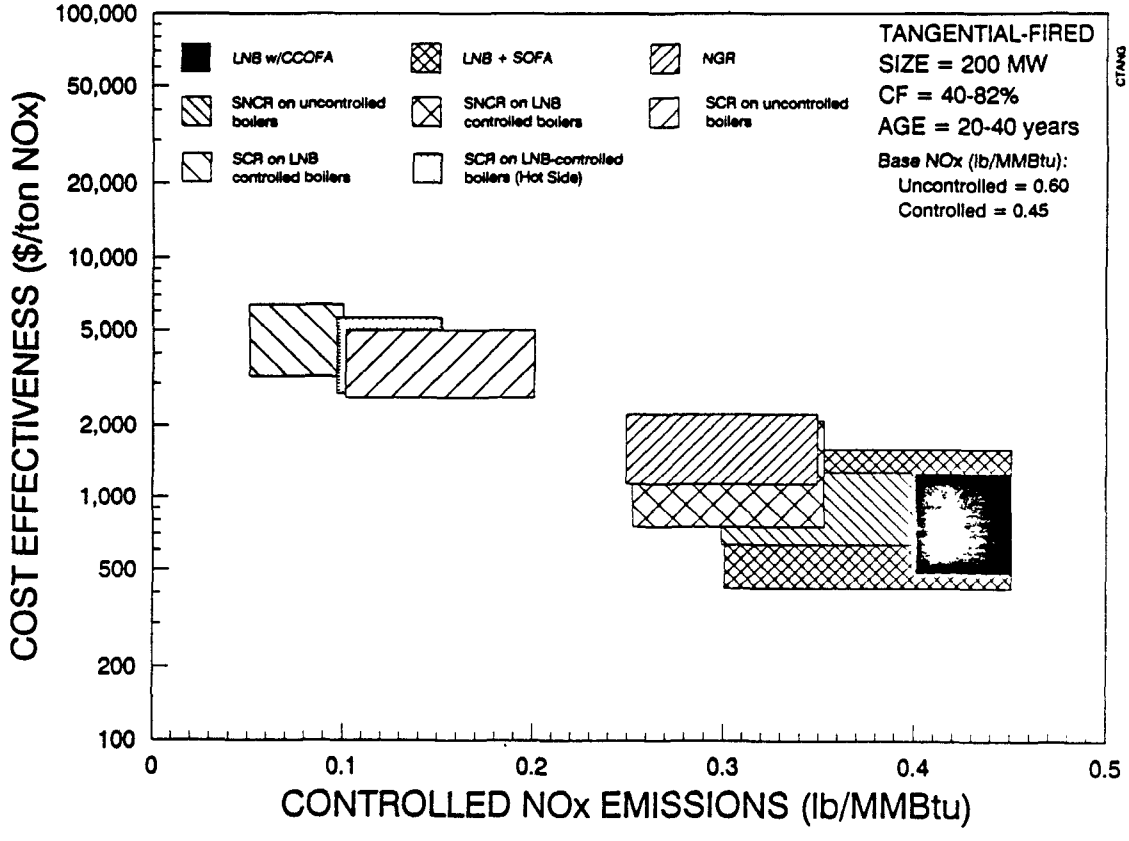

Figure 1-3. NO_x control cost-effectiveness for PC tangential-fired utility boilers

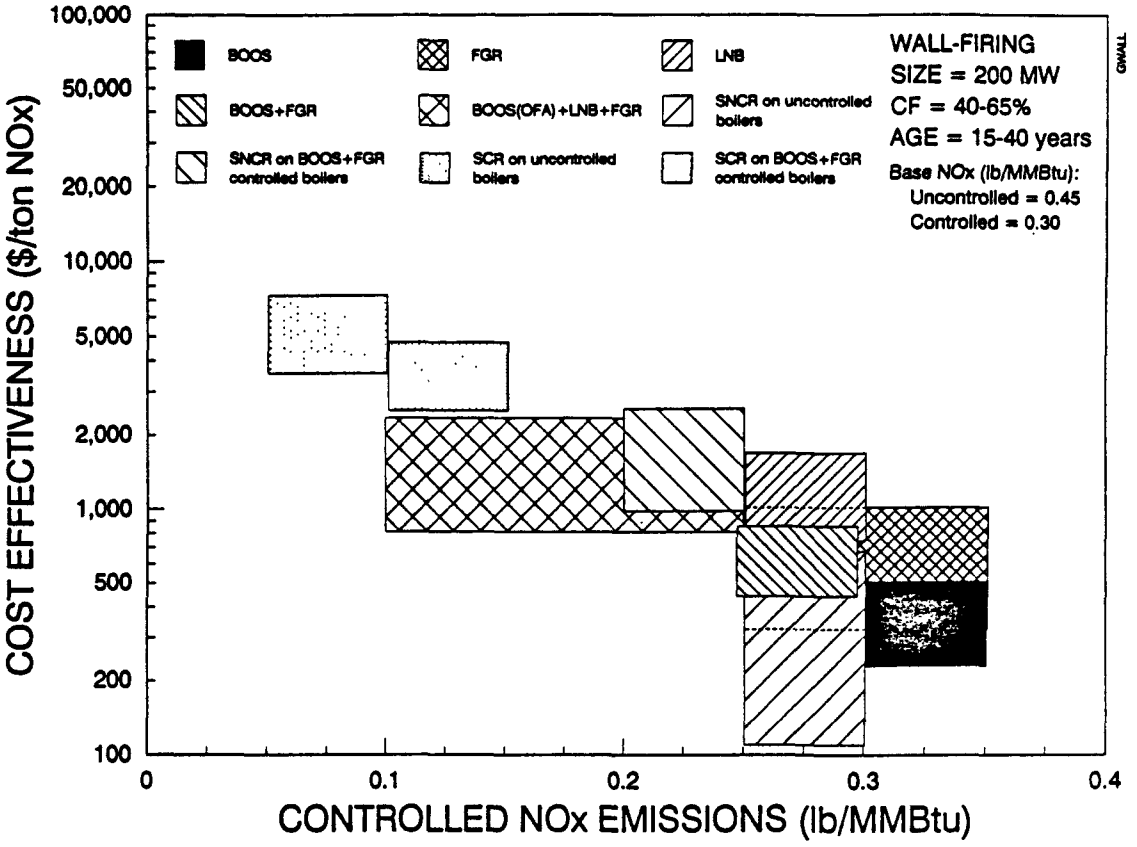

Figure 1-4. NO_x control cost-effectiveness for oil/gas wall-fired utility boilers

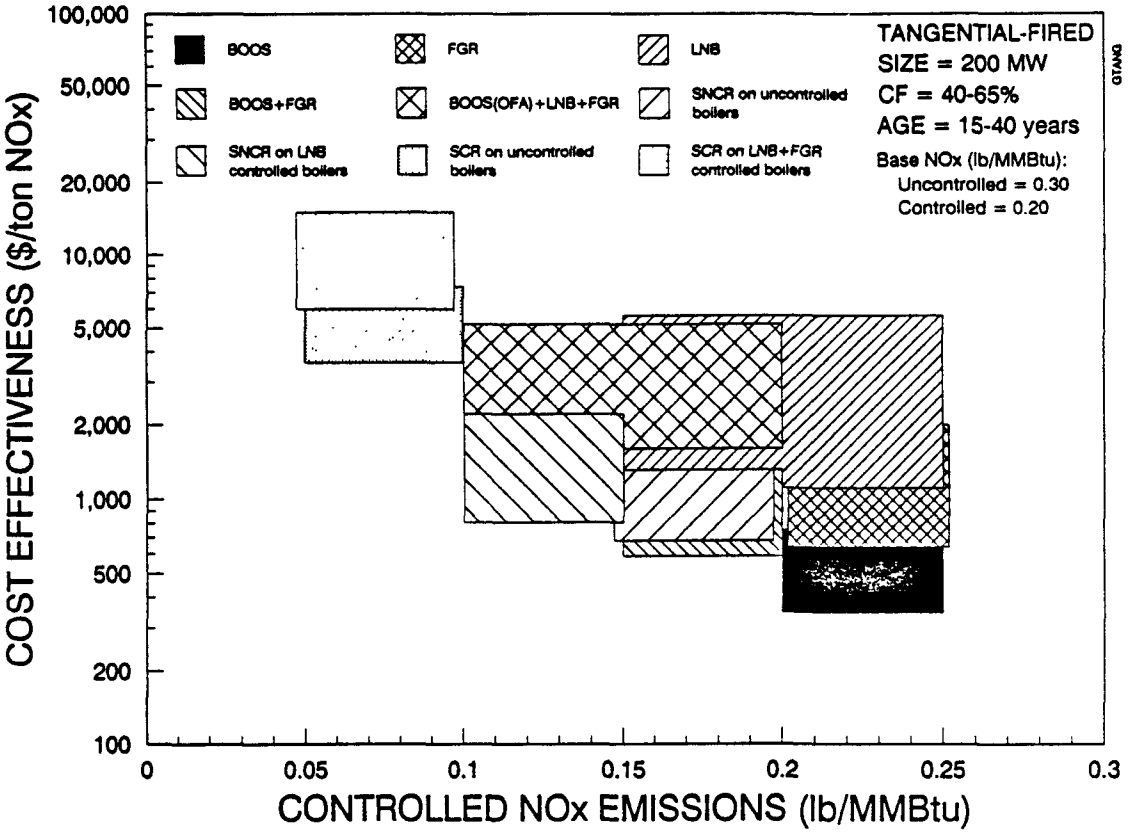

Figure 1-5. NO_x control cost-effectiveness for oil/gas tangential-fired utility boilers

combination of BOOS (or low-NO_x OFA ports) coupled with FGR can achieve NO_x levels of 0.10 to 0.20 lb/MMBtu when burning natural gas. However, these levels are much less likely when burning low-grade residual oils. With these fuels, combustion modifications will be limited by the onset of inefficient combustion, soot emissions, and increased carbon content in the fly ash. Controls that aim at reducing NO_x, once it is already formed, in the furnace or convective passes of the boiler, offer further potential for additional NO_x reduction. Some of these controls (e.g., NGR and SNCR) may prove to be cost competitive with combustion modifications. The combination of combustion controls and noncatalytic controls (NGR or SNCR) can achieve NO_x levels almost as low as the levels achieved using SCR technology.

The 1987 NO_x emissions from all utility boilers in the NESCAUM region totaled approximately 380,000 tons. Application of LNB based controls to 80 percent of the currently uncontrolled dry bottom PC-fired boiler population is expected to reduce NO_x by 29,000 to 42,000 tons/yr. The control of 50 to 80 percent of the cyclone and wet-bottom boiler capacity with NGR coupled with LNB retrofit on dry-bottom units will reduce NO_x by about 48,000 to 70,000 tons/yr throughout the region. Control of oil-/gas-fired boilers to a system-wide level of 0.3 lb/MMBtu will add another 29,000 tons/yr reduction throughout the region. The overall cost of these controls is anticipated to be less than $1,000/ton of NO_x removed, in most cases.

SECTION 2

BOILER EQUIPMENT PROFILE

Combustion modifications are the principal methods to economically control NO_x from existing and new utility boilers. The retrofit feasibility, NO_x reduction performance, and costs of combustion controls are largely influenced by boiler design and operating characteristics such as firing configuration, furnace size and heat release rate, type of fuel, and boiler capacity factor, and condition of existing equipment. Many of these factors vary with the age of the unit. FGT controls can provide additive NO_x reduction from combustion-controlled levels. The retrofit feasibility and cost of FGT controls are often influenced by the fuel type, capacity factor, load dispatch profile, and several site-specific factors including site access and space availability.

This section examines the population of boilers in the NESCAUM region according to five primary classifications:

- Firing configuration (tangential, single wall and opposed, cyclones)
- Primary fuel (pulverized coal or oil/gas)
- Heat release rate (dry and wet bottom furnaces)
- Age
- Capacity factor

The purpose of grouping the boilers into these conventional classifications is to assign retrofit control technologies and to calculate potential NO_x reductions and costs applicable to the existing boiler profile in NESCAUM on the basis of broad retrofit assumptions. Retrofit controls are selected principally on the basis of the boiler's primary fuel, firing configuration and heat release rate. Low-NO_x circular burners, for example, are applicable to wall- or opposed-fired boilers. Control performance of these retrofits may vary from levels obtained from retrofit of corner-fired boilers. The age and capacity factor will often influence the ease of retrofit and the cost of NO_x reduction. It should not be construed that these are the only factors that influence the retrofit potential, performance, and eventual cost of NO_x controls. In fact, fuel characteristics of coal and oil, design of existing furnaces, and overall operational status of equipment are but a few other site-specific factors that will influence actual performance and cost of applicable controls.

The boiler population profile, NO_x emissions, and fuel consumption data presented in this section are based on information reported in the EPA's National Utility Reference File (NURF) supplemented with energy consumption data from DOE's Energy Information Administration (EIA), Form EIA-767 annual report (Pechan, 1989), and information obtained directly from the utilities. Appendices A and B provide a listing of the data on the boiler population in the NESCAUM region.

2.1 FIRING CONFIGURATIONS AND FUEL TYPES

The type of NO_x combustion control selected for a specific boiler type must be compatible with the existing design of the units and the fuels. For example, burners out of service (BOOS), a popular and inexpensive operational modification that uses combustion air staging for NO_x control, is generally not preferred for PC-fired boilers because of modifications necessary to the coal pulverizers. Existing PC units are for the most part not adaptable to redistribution of coal feed but must rely on other equipment modifications to take advantage of the air staging approach in NO_x control. Because of compact furnaces, installation of OFA ports in some pre-NSPS pulverized coal-fired boilers can be severely limited to minimize the loss in unburned carbon in the flyash, furnace exit temperature, and slagging and corrosion of furnace walls. Slagging furnaces are not adaptable to many combustion modifications. Vertical-, turbo-, cyclone- and stoker-fired boilers offer fewer control options than other coal-fired boiler designs. As discussed below, NO_x emissions from vertical-, turbo-, and stoker-fired boilers are a small portion of the total utility boiler NO_x inventory in the NESCAUM region. Cyclone and wet-bottom units, although few in number, can be an important retrofit target because of generally high uncontrolled NO_x emissions.

Table 2-1 summarizes the population of utility boilers according to firing configuration and primary fuel type. The 200 units listed account for more than 99 percent of the existing capacity and current utility fossil fuel consumption in the NESCAUM region. Many boilers have multifuel

Table 2-1. NESCAUM boiler inventory by firing type and fuel: number of units (capacity in MWe)

Firing Type	Primary Fuel Type[a]			
	Coal	Oil	Gas	Total[b]
Tangential	21 (3,170)	33 (8,210)	29 (4,640)	83 (16,000)
Opposed	5 (1,980)	12 (3,160)	5 (1,390)	22 (6,530)
Wall	16 (1,790)	24 (5,120)	25 (3,980)	65 (10,900)
Cyclone	4 (760)	3 (310)	4 (760)	11 (1,830)
Vertical	5 (370)	3 (160)	3 (150)	11 (680)
Stoker	8 (160)			8 (160)
Total	59 (8,220)	75 (17,000)	66 (10,900)	200 (36,100)

[a]Many oil- and gas-fired boilers burn both fuels.
[b]All reported capacities are rounded to three significant digits.
Source: EPA's NURF, DOE's EIA-767 survey, and utilities data.

capability and burn one fuel or the other depending on fuel pricing and availability, which vary on a seasonal basis. Multifuel firing capability is particularly the case for oil- and gas-fired units. In 1987, approximately 60 percent of the gas and oil capacity burned both fuels with each fuel contributing at least 10 percent of the total fuel consumption (on a Btu basis). Throughout NESCAUM, fuel oil accounted for 65 percent of the fuel consumption in 1987 for oil-/gas-fired boilers. The distinction that is made between oil- and gas-fired boilers in Table 2-1 was based on the percent of the fuel consumed during the 1987 base year. For example, if oil accounted for 51 percent or more of the total fuel consumed in the unit, then the boiler was categorized as an oil-fired boiler. However, when data were available on the emission factor for each fuel (gas and oil), the reported NO_x emission factor for gas-/oil-fired units was based on the proportion of quantity of each fuel consumed in 1987. For coal-fired boilers, only 6 percent of the available capacity burned another fuel.

Figure 2-1 illustrates the contribution of major boiler design types to the total NO_x emitted in 1987 from all utility boilers in the NESCAUM region. The emission level in 1987 was calculated using the emission factor in lb/MMBtu for individual boilers and the 1987 fuel consumption data in 10^9 Btu provided in the EPA NURF and DOE EIA data base and supplemented with data obtained directly from the utilities. The data show that the major emitters of NO_x emissions are tangential coal, tangential oil-/gas-, wall and opposed coal-, and wall and opposed oil-/gas-fired boilers, each category contributing approximately an amount ranging from 14 to 24 percent. Coal-fired slagging furnaces which include cyclone and wet bottom wall-fired boilers contribute 18 percent to the total utility NO_x budget. The combined NO_x output of other boiler designs including stokers and vertical fired units burning all fuels contributes only 3 percent to the total NO_x emitted by utilities in the region.

PC-fired boilers account for about 20 percent of the total capacity. Among PC units, tangential- or corner-fired designs account for nearly 40 percent of the capacity, followed by opposed firing (24 percent), and wall-firing (22 percent). From a hardware modification point of view, all opposed-, front-, and wall-fired boilers can be considered as one design configuration, as many of the combustion NO_x controls developed for wall-fired boilers are equally applicable to single- or opposed-wall-fired units. When taken as a whole, wall- and opposed-fired units account for nearly half the fuel-based capacity (46 percent for coal and 49 percent for oil and gas combined).

Another important design distinction among PC-fired boilers is whether the furnace is of the slagging type or not. Slagging furnace, also known as wet-bottom furnaces or slag tap furnaces, operate at higher temperatures so that the ash deposits on the furnace waterwalls (slag) are sufficiently fluid to fall in the bottom hopper without sootblowing assistance. Two tangential-fired boilers (174 MWe total) at the Somerset Station and seven wall- and down (vertical)-fired boilers (1,067 MWe total), primarily at the Mercer and CR Huntley Stations, are listed as wet-bottom furnaces in the NESCAUM inventory. In the early 1950s to about 1967, Combustion Engineering introduced only few (estimated at less than six) wet-bottom tangential boilers. Wet-bottom furnaces were more popular in the wall- and opposed-fired design. Because of the higher combustion temperature and the requirements for a certain higher heat release per unit of waterwall area, the uncontrolled NO_x level from wet-bottom boilers is generally higher than dry-bottom furnaces and combustion modifications are typically limited in applicability and effectiveness.

Stoker boilers are generally much smaller in size than PC units and constitute an older vintage coal-fired design for utilities. In the NESCAUM region, stokers account for less than one half percent of the total installed capacity. Therefore, their total contribution to the NO_x inventory in the region is expected to be minor compared to PC units. Since early-1980s research sponsored by EPA on the retrofit of combustion modification controls to reduce NO_x from stoker boilers, little

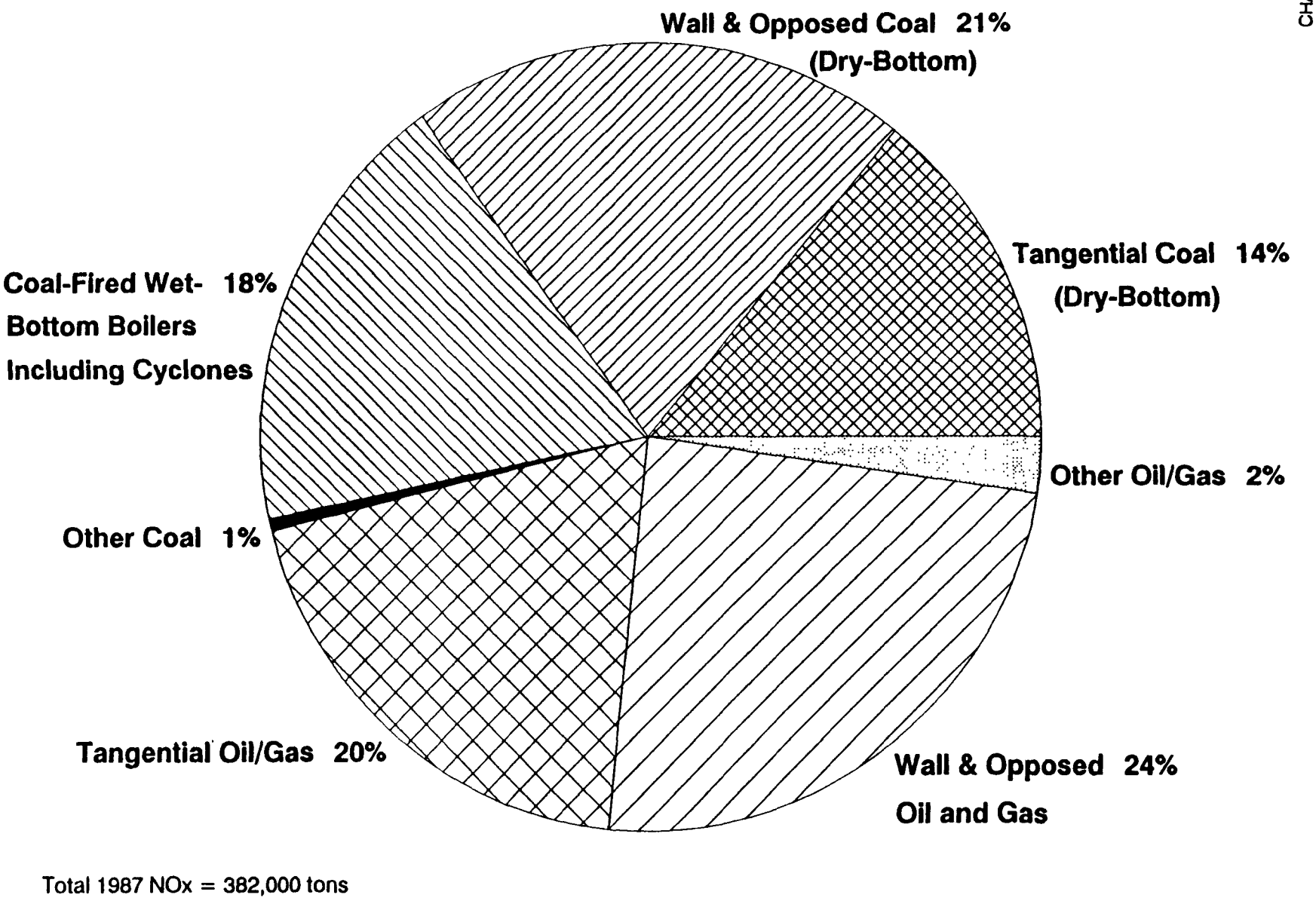

Figure 2-1. Contribution of boiler/fuel types to the total utility NO_x inventory

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additional operational experience has been gained (Maloney, 1983). Existing utility stokers have generally remained uncontrolled. Cyclone-fired boilers are a particular design introduced in the 1960s, primarily for low-volatile eastern bituminous coal burning. In the NESCAUM region there are 10 such units, with nearly half of the capacity coal-based and the other oil-/gas-based. Because of their characteristically high-NO_x emission rate, cyclones although few in number and capacity, are an important part of the overall NO_x inventory and control strategy. These units, along with wet-bottom furnaces, are therefore evaluated for NO_x reduction potential in the present study. Vertical or down firing configurations are included in the "other" category. These units, accounting for less than 3 percent of the oil-/gas-fired capacity, are not a major contributor to the NO_x inventory; therefore, they are not evaluated in this study.

2.2 AGE OF BOILERS

The design of utility boilers has undergone some important changes over the past few decades. These changes influence the applicability of combustion controls and are often a measure of the retrofit difficulty of the hardware and the attainable control efficiency.

The furnace and burner design practices of the past six decades can be divided into three principal time periods. The early boiler designs represented by units installed prior to the 1960s (greater than 30 years of age) were generally built with large furnace volumes and low volumetric heat release rate. Many designs are also negative draft with poor combustion air management and distribution to the burners. The larger furnaces were often necessary to achieve high combustion efficiency with high rank coals. Also, low furnace exit temperatures were necessary for fouling control and because of steam temperature limitations. Burner designs were not very sophisticated, providing inadequate burner air management by today's standards. Many of the boilers were generally of low firing capacity compared to large units built today that take advantage of the economy of scale. Because of the low capacity and poor burner control system and combustion air management, these older units present greater retrofit difficulty and hardware upgrade. These units also have a lower utilization (capacity factor) due to higher plant heat rates (Btu/kWh).

The decade of the 1960s was the second distinctive period for utility boiler designs. During this time, increased competitiveness among boiler manufacturers and improved combustion technology and material science contributed to the design of more compact boiler furnaces, larger capacity units, and larger burners with better combustion air control. High combustion turbulence (mixing) and higher temperatures were emphasized in the design for better combustion efficiency. Unfortunately, these design conditions also led to higher NO_x levels. For PC-fired boilers, greater emphasis was placed on low-volatile coals which, under unstaged combustion conditions, also contribute to higher uncontrolled NO_x levels. Because of the higher baseline NO_x emissions, these 20- to 30-year old units have the potential for large NO_x reductions with the retrofit of current low-NO_x combustion technologies. Some designs, such as cyclones and opposed cell-burner units however, present significant retrofit challenges. Only recently have combustion controls been investigated for these units and commercialization of the technologies awaits key demonstrations.

The third period spans the past 20 years, the post-NSPS period (Subpart D boilers). Starting in 1971, new orders for utility boilers called for technologies capable of compliance with new NO_x regulations (Subpart D). Later, in 1978, more stringent regulations went into effect (Subpart Da). Because the NSPS applied to new orders, some units with startup dates as late as 1975 were exempt from regulations. Fuel conversion boilers (units that switched from gas and oil to coal) also had to comply with these regulations. This motivated some important changes in the way manufacturers designed their coal-fired furnaces and burners. Tangential units, built by Combustion Engineering (CE), now Aesea Brown Boveri (ABB), which were traditionally a lower NO_x emitter, started to

introduce SOFA as a means of ensuring compliance. In reality, tangential units were usually well below the 1971 NSPS levels. Babcock & Wilcox (B&W), Foster-Wheeler Energy Corporation (FWEC), and Riley Stoker (now a member of Deutsche Babcock Group), builders of wall-fired boilers enlarged their furnaces to reduce heat release rate and peak temperature. Larger furnaces were also required as lower volatile coals were increasingly used. A recent survey of 200 coal-fired boiler designs showed that furnace volumes of post-NSPS boilers were increased 40 percent (Emmel and Maibodi, 1991). Although some boilers were equipped with OFA as a safety measure to meet NSPS limits, manufacturers of these units, and owners/operators, did not rely on OFA ports because of the potential impact on unburned carbon and steam temperature control and because of concern over corrosion (Lisauskas, 1987). This was also the time when cyclone, wet-bottom furnaces, and cell burners (closely coupled burner outlets) were discontinued. In the late 1970s, some boilers were converted to coal burning while new wall-fired units were introduced with advanced coal burners and OFA capability to meet more stringent NSPS levels (LaRue, 1990).

With this information as background, Figures 2-2 and 2-3 illustrate the trend in boiler capacity versus age for the coal- and oil-/gas-fired boiler population in the NESCAUM region. Clearly, the newer boilers have generally higher capacity. The trend is most evident in the tangential and opposed-fired units. Immediately following the initial 1971 NSPS, only one new coal-fired boiler was introduced in the NESCAUM region, the opposed-fired 675 MWe Somerset Unit 1. This post-NSPS coal-fired boilers must comply with the 1978 NSPS NO_x limits. Several other older boiler were modified during the past 10 years to burn pulverized coal. These fuel-switching units include 600 MWe of opposed firing, 520 MWe of tangential firing, and nearly 560 MWe of wall firing.

Figure 2-4 illustrates the distribution of boilers according to age. The data show that, when excluding fuel switching units, less than 20 percent of the oil- and gas-fired units were commissioned in the past 20 years (post-NSPS). Past this period, the trend is similar for all boilers irrespective of fuel, meaning that at any given percentage, oil- and gas-fired units are generally as old as coal units. Figure 2-5 illustrates the same data on a capacity basis. Here the data show that less than 10 percent of the coal-fired boiler capacity was introduced in the post-NSPS time. When fuel switching units are counted, the total PC-based capacity introduced in the post-NSPS period accounts for 34 percent of the total. In the same period of time about 40 percent of the current oil- and gas-based capacity was put online.

2.3 CAPACITY FACTOR

The capacity factor is defined as the percent of the boiler maximum capacity that was utilized throughout the year. For example, a unit whose maximum continuous rating is 300 MWe can generate 2.63 GWh of electricity in one year operating continuously at full load. However, boilers do not operate in this manner since they require routine maintenance during scheduled outages. Also, the system for dispatching power means that less efficient units are generally operated less frequently than more fuel-efficient units. Finally, load demand varies over a 24-hour period and from season-to-season. Less efficient boilers are not operated at constant base load but are made to vary according to peak demands. Therefore, most boilers operate only a fraction of the time available in any one year and at an average load that is lower than the maximum continuous rating (MCR).

The capacity factor is an important variable for estimating the overall NO_x reduction benefit and the cost effectiveness of control technologies. A boiler with a very low capacity factor will typically have a higher cost ($/ton of NO_x removed) than a boiler with a much higher capacity factor. As heat rates are generally lower for newer and base-loaded boilers, the NO_x control costs

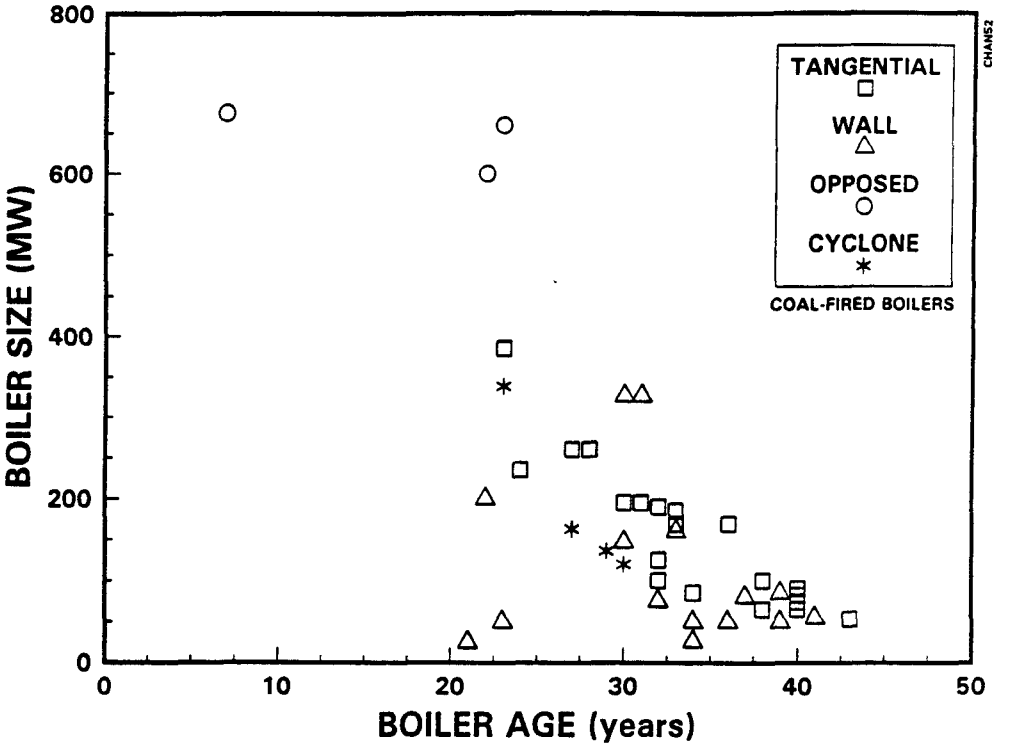


Figure 2-2. Trends in coal-fired boiler sizes with age for the NESCAUM region

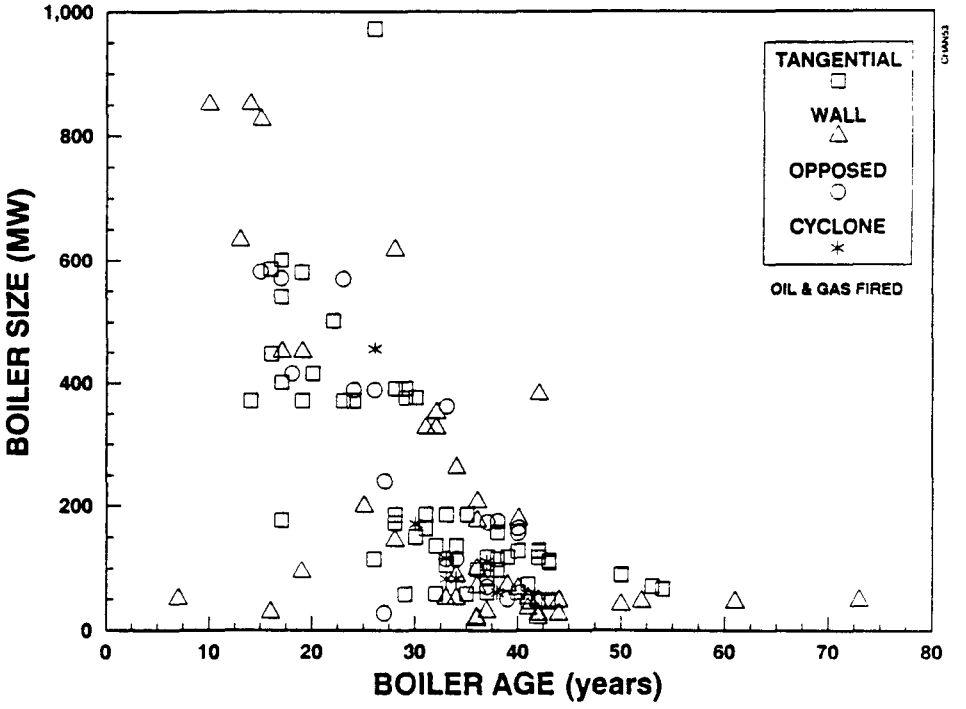


Figure 2-3. Trends in oil-/gas-fired boiler size with age for the NESCAUM region

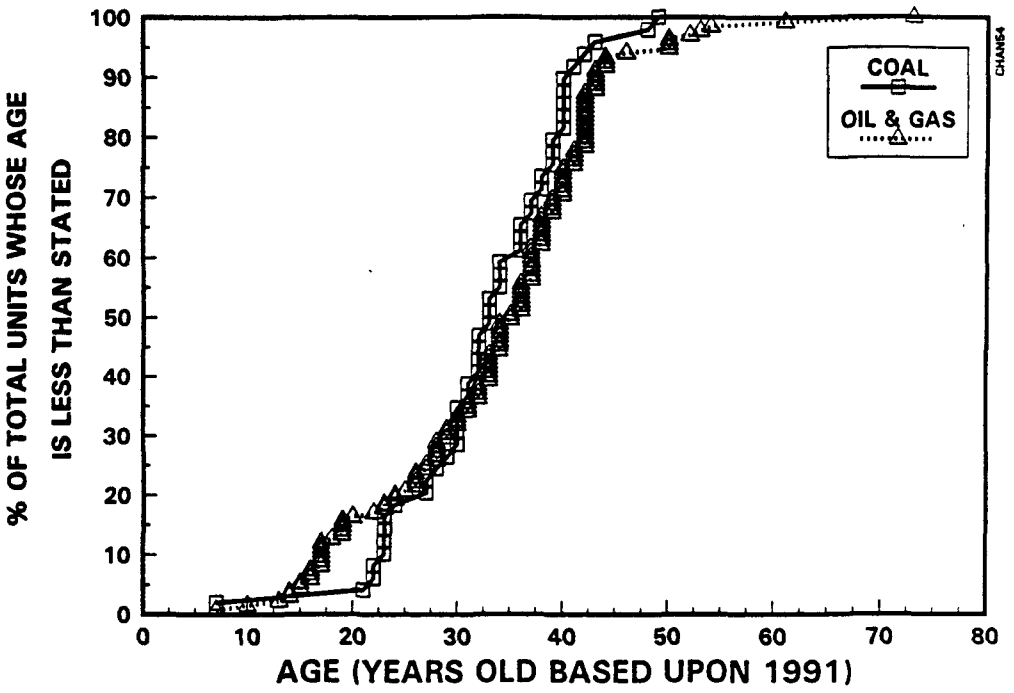


Figure 2-4. Distribution of NESCAUM boilers—number of units versus age

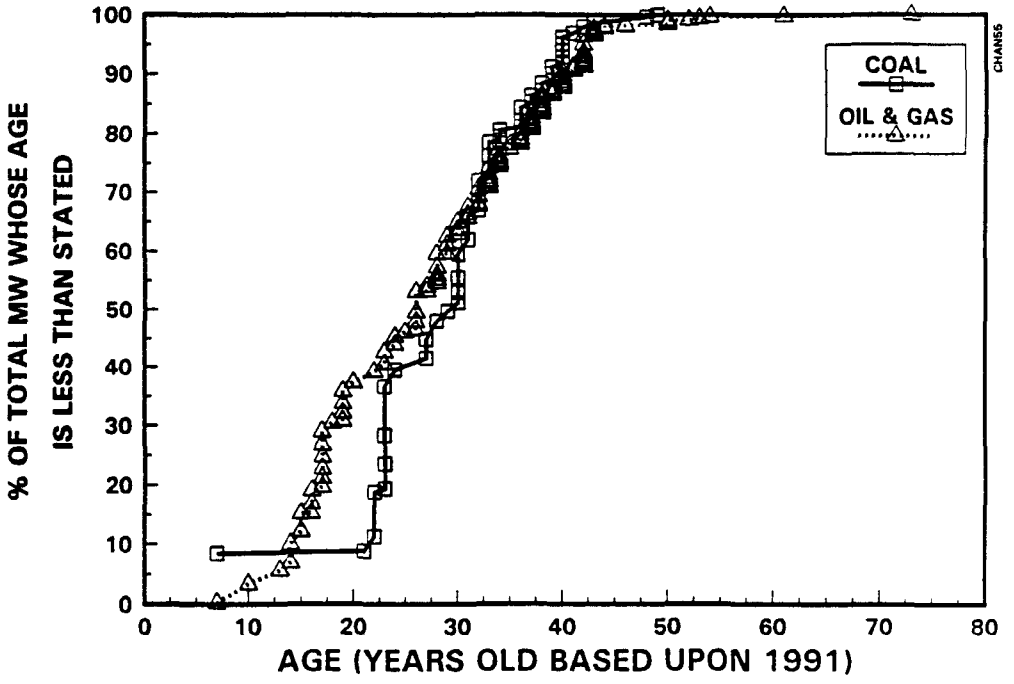


Figure 2-5. Distribution of NESCAUM boilers—total MW versus age

associated with these units are lower because such units have higher capacity factors. This assumption is not always valid, however, because older units, although generally used less often than newer units, can be high emitters of NO_x, and even a small percentage reduction can offer significant total systemwide reductions. Examples of such units are the slagging or wet-bottom coal-fired boilers and the cyclone-fired boilers. As noted earlier, coal-fired cyclone and wet-bottom PC-fired boilers account for 17 percent of the total NO_x in the NESCAUM region. Those cyclone boilers in service for nearly 30 years have capacity factors typically in the range of 60 to 80 percent.

In this report, we used the most recent 1987 fuel consumption data reported by Form EIA-767 to calculate the capacity factor of each boiler in the NESCAUM region (Pechan, 1989). The reported fuel consumption was then translated to an equivalent electrical output using the heat rate reported by the utilities for their respective power plants. For the New York Power Pool (NYPP), heat rates of boilers were based on data reported in a recent study for the Empire State Electric Energy Research Corporation (Hunter, 1989). Some utilities reported capacity factor data for the 1990 year. In a few cases when this information was not available, a standard 10,000 Btu/kWh heat rate was used. The calculation of capacity factor, using the boiler steam turbine generator rated MW and a nominal heat rate for the unit, is subject to uncertainty. This is because the heat rate varies according to boiler load and fuel mix. A more correct calculation would have used the rated firing capacity of the boiler. However, this information was not readily available for the majority of the units. The heat rate of a boiler will vary with load, age and design. For the NESCAUM boilers, the gross heat rate is likely to be in the range of 9,500 to 14,000 Btu/kWh.

Figure 2-6 illustrates the distribution of units according to boiler capacity factors. The data clearly shows that coal-fired boilers have a higher utilization rate, and more than 80 percent of all units had a capacity factor greater than 50 percent. The trends for oil- and gas-fired boilers are similar. Only about 30 percent of all the units had a capacity factor greater than 50 percent in 1987. Figure 2-7 illustrates the same data on a capacity basis. Here the data show that about 80 percent of the coal-fired boiler capacity, approximately 8,000 MWe, was on line at least 50 percent of the time. Of the approximate 28,000 MWe of combined oil- and gas-fired boiler capacity, only about 30 percent had a capacity factor greater than 50 percent, significantly lower than PC-fired boilers.

2.4 SUMMARY OF POPULATION DATA

Figures 2-8 and 2-9 illustrate the distribution of existing coal- and oil-/gas-fired boilers in operation in 1987 in the NESCAUM region, respectively. The capacity of these units is segregated by age of boilers. The figures also give data on the weighted average capacity factor (WACF, see glossary for definition) for each group of boiler designs in that time period. The average capacity factor is weighted according to the size of the boiler. The single post-NSPS coal-fired boiler has a capacity factor (81 percent) higher than all other units from any other age group or fuel type. Also the average capacity of the newer units has increased. Stokers and vertical units not only account for very little capacity but also have a lower operating factor, here calculated at an average of 51 percent. Stoker boilers have heat rates in the range of 14,000 to 15,000 Btu/kW, much higher than most other boiler design types.

Contrary to coal-fired units, less total oil-/gas-fired capacity was added in the past 20 years than in the previous 20 years. Because of fuel economies, the overall capacity factors for these units are generally lower than those for coal. Wall-fired boilers show an unusually low capacity factor regardless of the age of the units. For example, in 1987 post-NSPS oil-/gas-fired boilers showed a capacity factor of only 33 percent, 6 percent for units of 21 to 30 years of age, and 25 percent for units of 31 to 40 years of age. It is likely that these boilers were used to follow load demand and

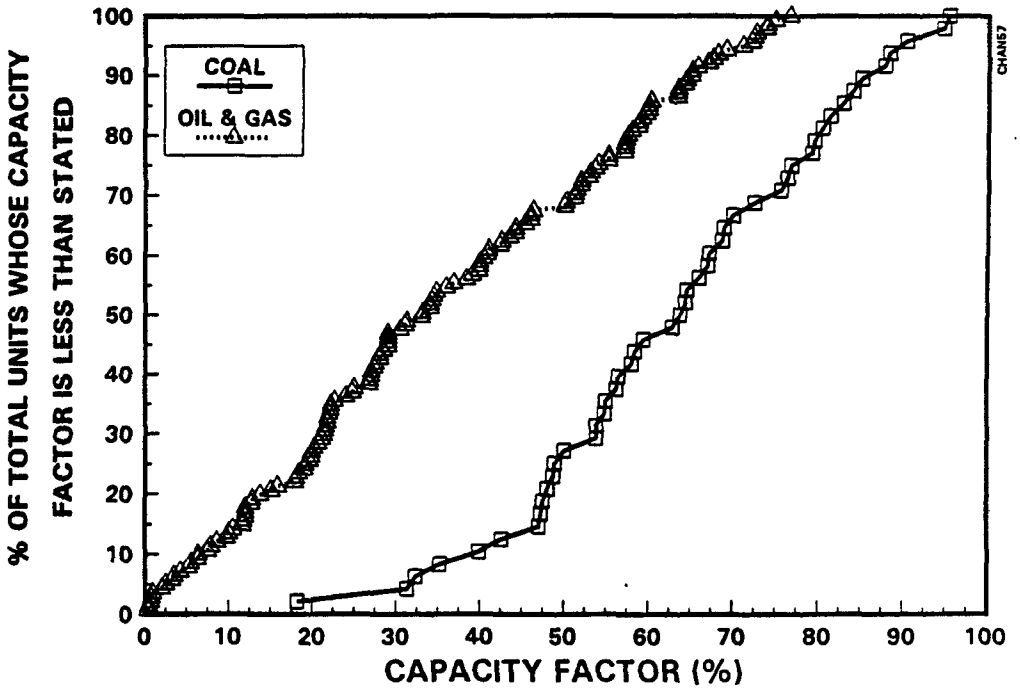


Figure 2-6. Distribution of NESCAUM boilers—number of units versus capacity factor

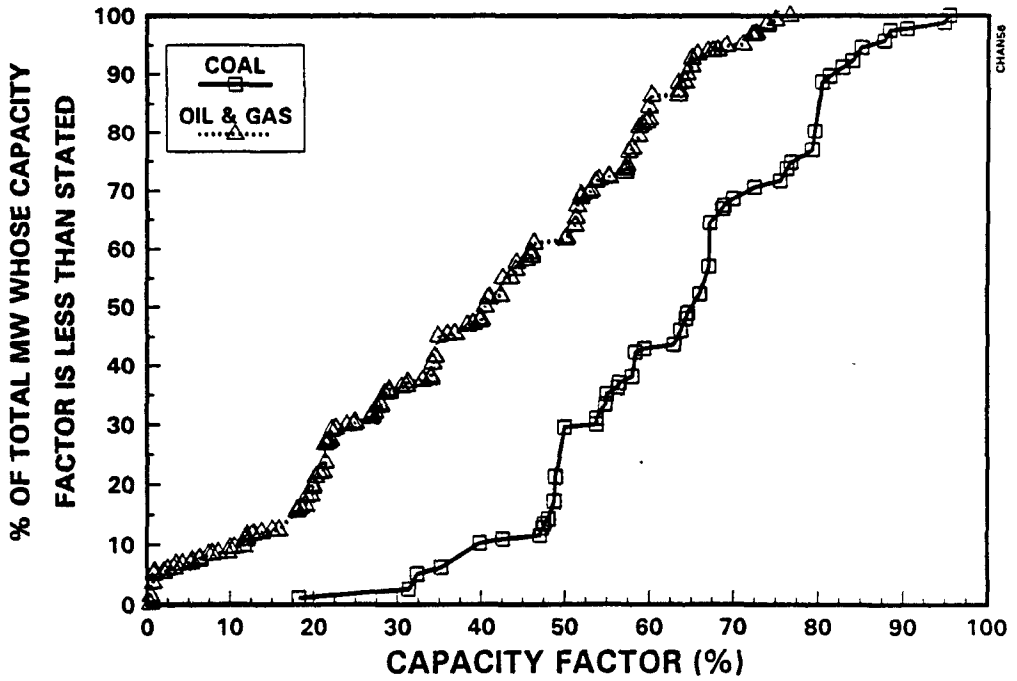


Figure 2-7. Distribution of NESCAUM boilers—total MW versus capacity factor

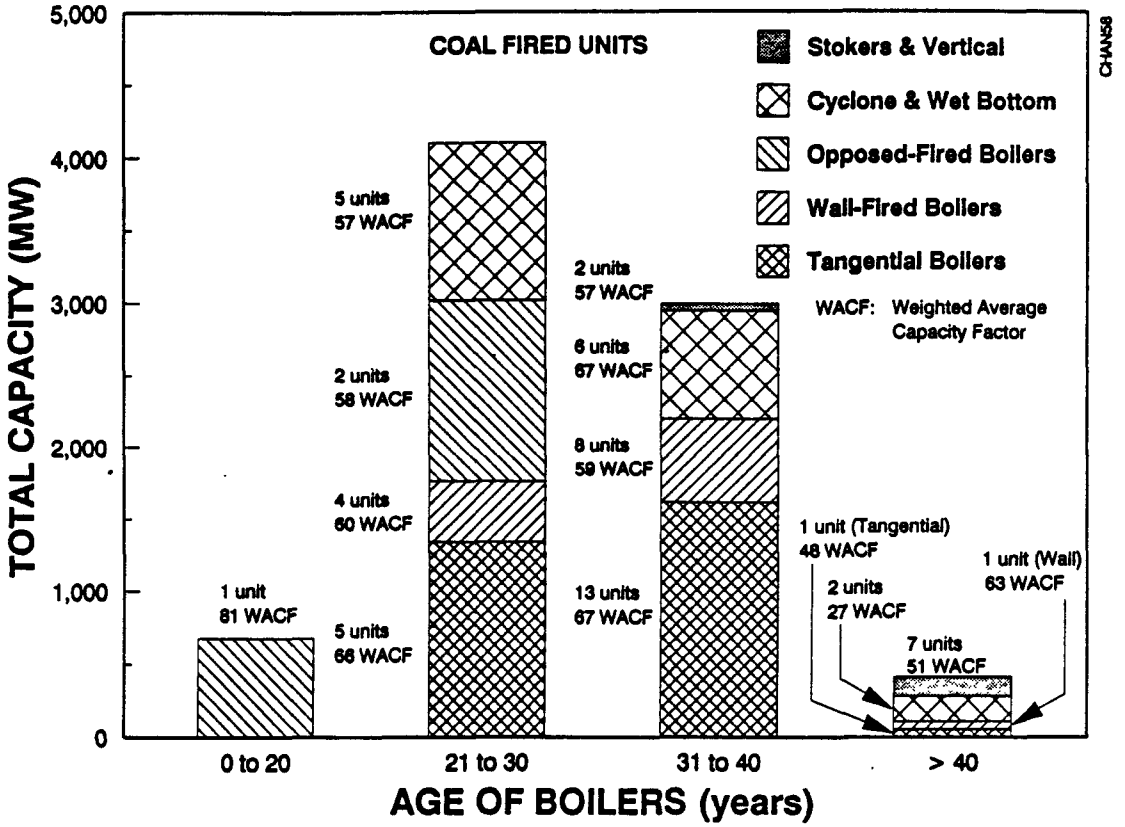


Figure 2-8. Age distribution of coal-fired boilers

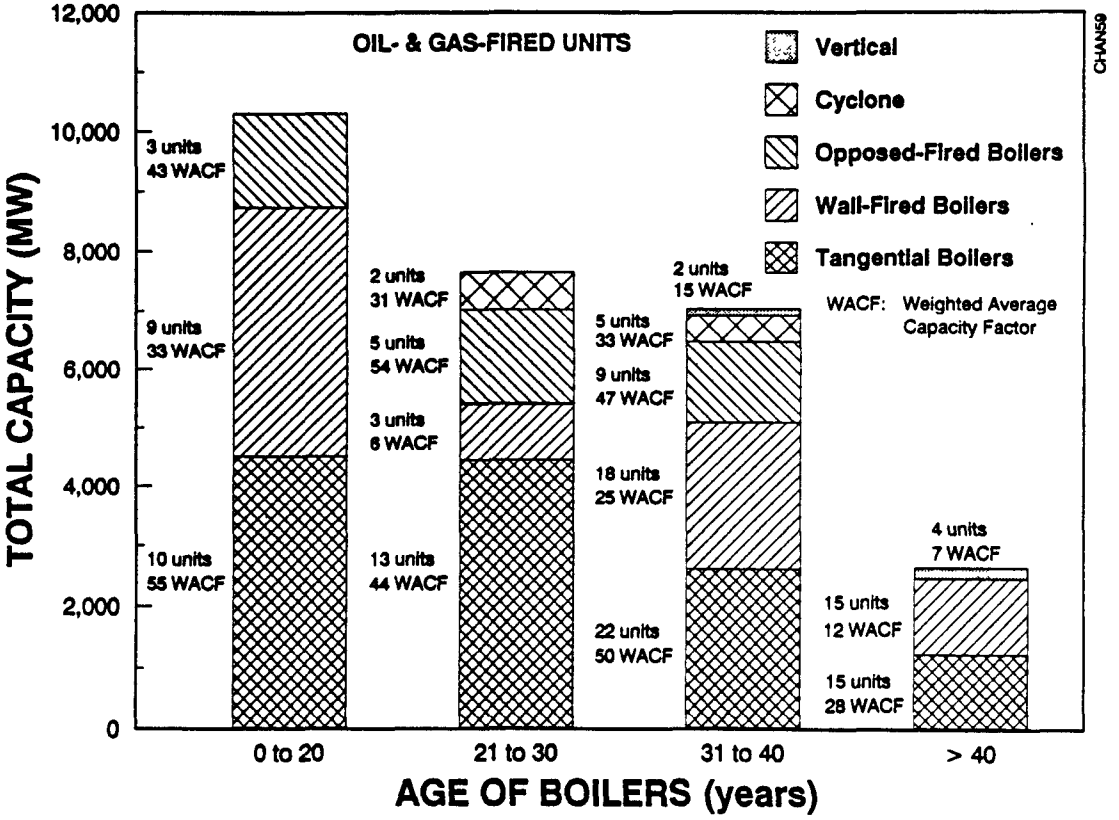


Figure 2-9. Age distribution of oil- and gas-fired boilers

for peaking power needs, whereas coal-fired boilers were more base load units. Cyclone and vertical fired boilers account for minor capacities even when considered in their own age groups.

Figures 2-10 and 2-11 illustrate the NO_x emission levels attributed to the various coal- and oil-/gas-fired boiler groups, respectively. The low PC-fired post-NSPS boiler is attributed with about 12,000 tons/year of NO_x. Among coal-fired equipment, the largest NO_x sources are the slagging units (wet bottom and cyclone) followed by tangential boilers, opposed and wall-fired boilers. Most of the NO_x is emitted by pre-NSPS boilers. Among slagging furnaces, cyclone units, although few in number, contribute significantly to the total NO_x inventory in the region (16 percent of the NO_x from all coal-fired boilers; 8 percent of the total utility boiler NO_x). As shown, stoker boilers are relatively insignificant NO_x emitters when compared to other boiler types. For oil-/gas-fired boilers, the tangential firing designs as a whole contribute the bulk of the NO_x emissions. In contrast with PC-fired boilers, post-NSPS oil- and gas-fired units account for a large fraction of total NO_x emissions. Vertical and cyclone boilers are minor contributors to the NO_x inventory.

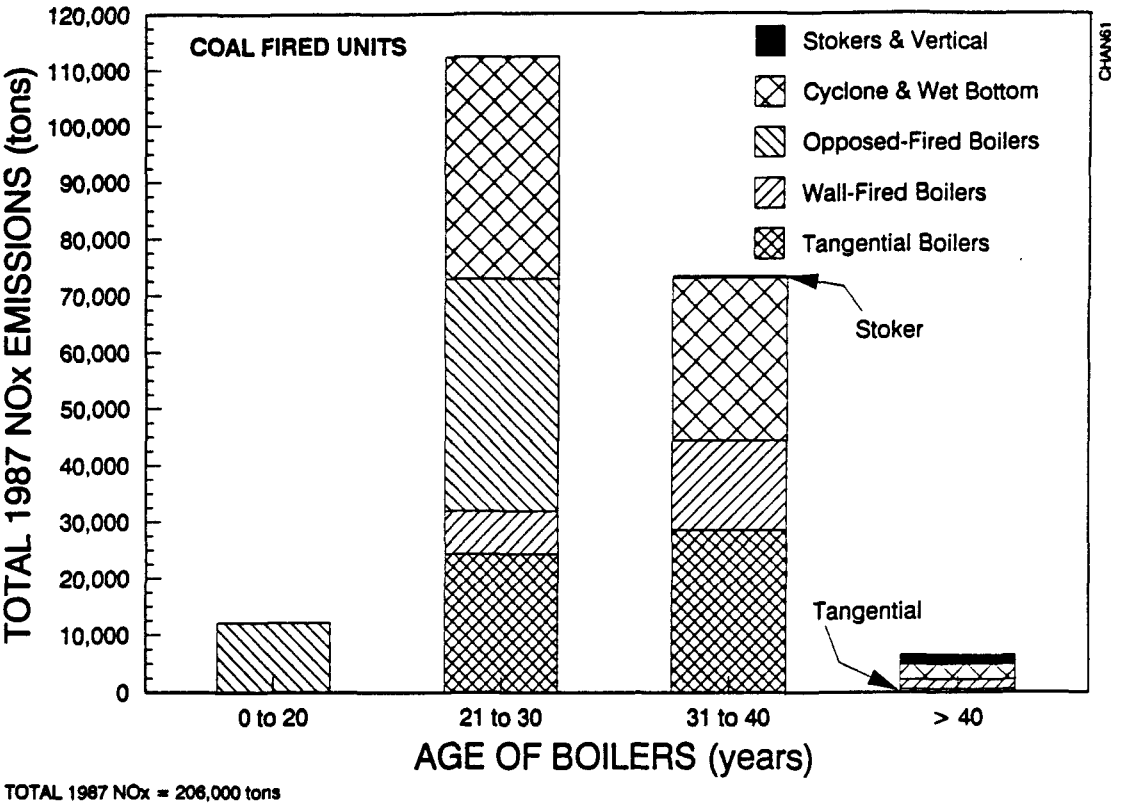


Figure 2-10. NO_x emissions, coal-fired boilers

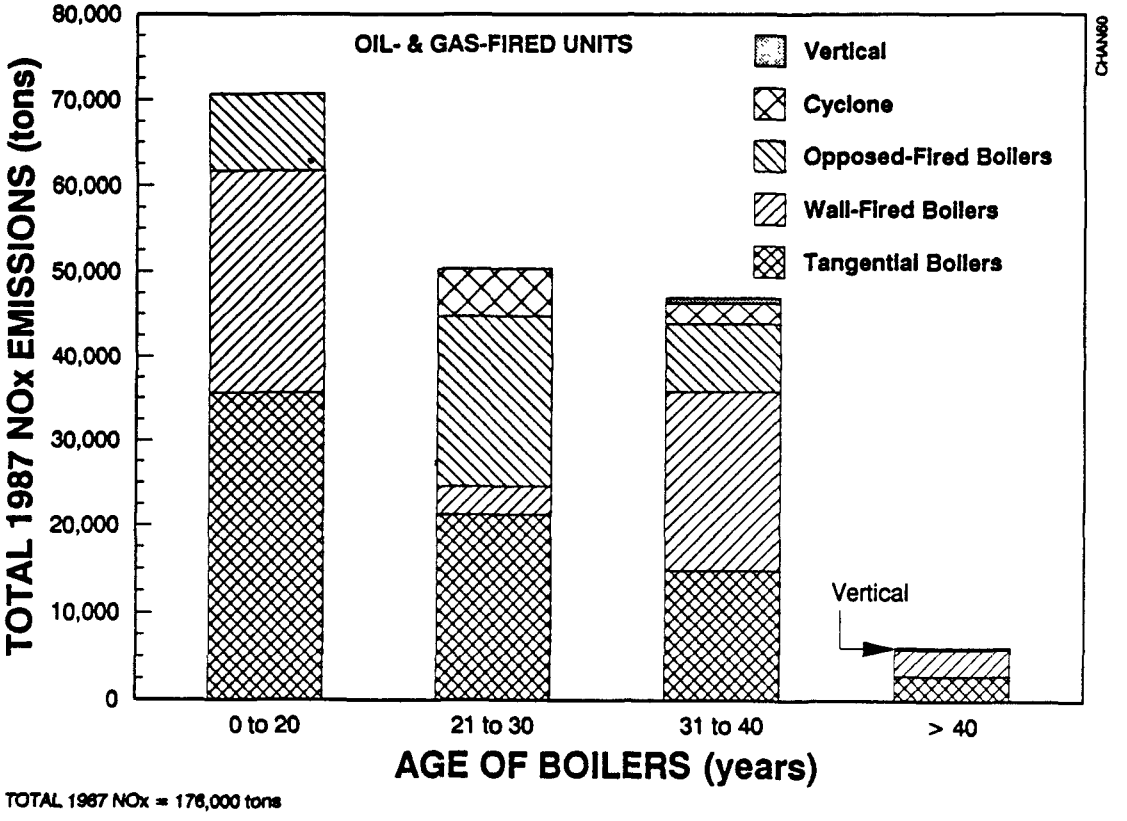


Figure 2-11. NO_x emissions, oil- and gas-fired boilers

SECTION 3

BASELINE EMISSION PROFILES

In this study, the term baseline NO_x is used to describe the current NO_x emission levels from utility boilers in the region. Because the vast majority of these boilers do not use NO_x controls, such as low-NO_x burners or flue gas treatment, the term can also be interpreted to mean uncontrolled NO_x emission levels. NO_x emissions from utility boilers are a function of fuel properties and many boiler design and operating variables. Among the most influential variables are the fuel nitrogen content, the excess air rate, the heat release rate per unit of waterwall area in the burner zone, the amount of air preheat, and the burner stoichiometry. When pulverized coal is burned, the fuel ratio (fixed carbon divided by volatile matter) and oxygen/fuel nitrogen ratio also influence the uncontrolled NO_x levels as well as NO_x levels achievable with combustion controls.

As the nitrogen content in the fuel increases so does the overall NO_x level. Generally, only a fraction of the total fuel-bound nitrogen is converted to NO_x. That amount is usually in the range of 20 to 80 percent when combustion is not staged as illustrated in Figure 3-1. The higher nitrogen fuels have lower conversion rates but higher overall NO_x emissions. For pulverized coal burning, the FR affects NO_x to a degree equivalent to fuel N. Typically, under unstaged combustion conditions lower fuel ratios (i.e., higher volatile content of the coal) correlate with higher production of NO_x. This is the result of greater amount of volatile nitrogen released in the high temperature zone of the flame where sufficient oxygen is available to generate high levels of NO_x. When the combustion is staged, the effect is the opposite. Figure 3-2 illustrates this combined effect of FR and fuel-bound N under staged combustion with two low NO_x burner technologies coupled with SOFA. The proprietary fuel factor developed by B&W illustrates that higher FR and N result in higher controlled NO_x levels. Therefore, staged combustion controls are typically more effective on high volatile content coals also known as reactive coals. Under combustion staging with OFA or low-NO_x burners, lower NO_x levels are attainable when burning subbituminous coals which have higher volatile and oxygen content than higher rank eastern bituminous coals. The effect of coal quality is important because performance results of low-NO_x combustion systems reported with one coal type cannot be interpreted to apply to other coal types. This distinction of NO_x performance with coal type is further highlighted in Section 4.

NO_x generally increases with excess air and the burner zone heat release rate (BZHRR). The BZHRR is a key boiler design parameter used by manufacturers to design furnace volumes and waterwall area according to fuel type and NO_x control requirements. BZHRR varies with the firing type, the age of the unit, the primary fuel type, and the operating load. For example, slagging or wet bottom furnaces have a high BZHRR necessary to achieve high furnace temperatures to maintain the slag in a fluid state. In a similar manner, the cyclone furnaces enclose the combustion of coal in a small refractory furnace creating high combustion temperatures that lead to much higher NO_x levels. As discussed in Section 2, all of these furnace designs were introduced in the late 1950s and 1960s when NO_x was not regulated. Because of their requirements for high furnace temperature, control of NO_x in these boiler types is extremely difficult. For gas- and oil-fired

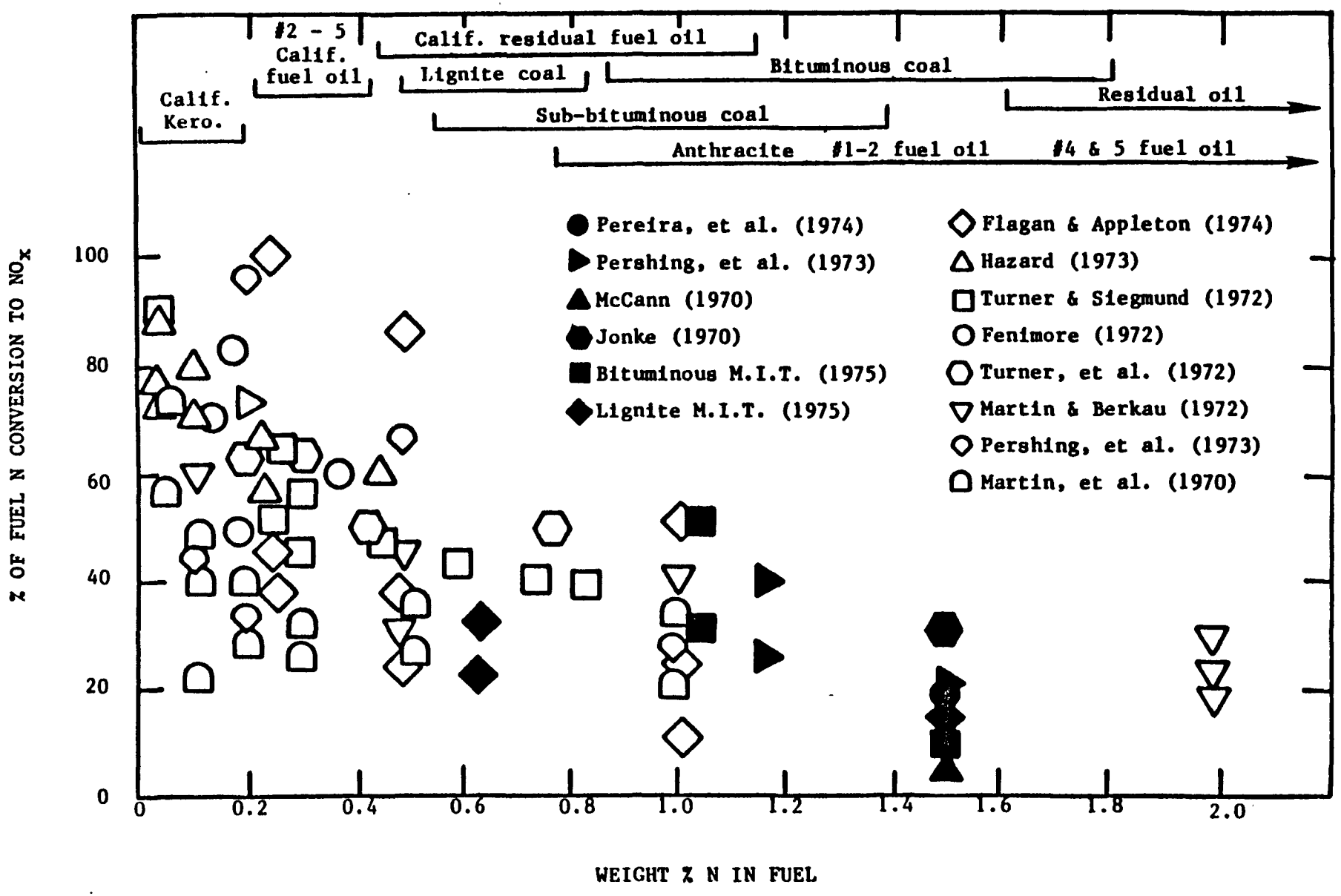


Figure 3-1. Conversion of fuel N in practical combustors (Habelt and Howell, 1976)

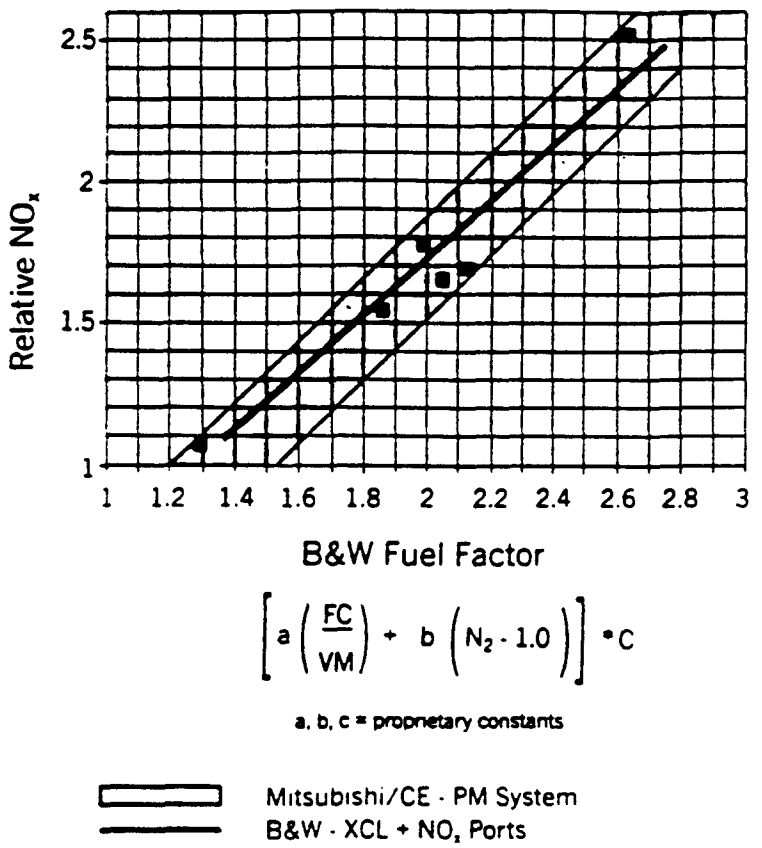


Figure 3-2. Fuel effect on NO_x (LaRue, 1990)

boilers, air preheat contributes to higher NO_x levels. Typically, all utility boilers utilize air preheat for improved thermal efficiency.

Figure 3-3 illustrates the variation in uncontrolled, pre-NSPS, NO_x levels for the various designs of PC-fired boilers. As shown, NO_x generally increases with boiler capacity for all boiler types. Slagging furnaces are the highest contributors to NO_x emissions. Existing tangentially-fired boilers are typically the lowest NO_x emitters. Newer wall-fired designs can often match the low emission levels of the ABB-CE boilers because of the recent breakthroughs in low-NO_x burner technologies.

Table 3-1 summarizes the uncontrolled emission factors for the major coal-fired boiler design groups in the NESCAUM region. Two emission factors are presented. The first is that reported in the NURF and current EIA data bases (Pechan, 1989) supplemented, when available, with information obtained directly from the utilities during the course of this study and with data presented in the ESEERCO study (Hunter, 1989). Where available, both the range and the average value (weighted according to capacity) for that boiler population is reported (see Appendix A for details). The second set of emission factors are those reported by the EPA for each boiler design/fuel category. The AP-42 emission factors are reported solely for companion purpose to establish the reasonableness of emission levels reported in the data base. These AP-42 emission factors are not used anywhere else in the report.

A review of the boilers' emission rate for the post-NSPS boilers shows that the Kintigh Unit 1 coal-fired utility boiler, with a reported startup data in 1984, meets the regulatory limit of 0.6 lb/MMBtu introduced in 1978 for bituminous-coal-fired boilers. Other areas of general agreement between NO_x emissions factors reported by this study and those in AP-42 include all dry

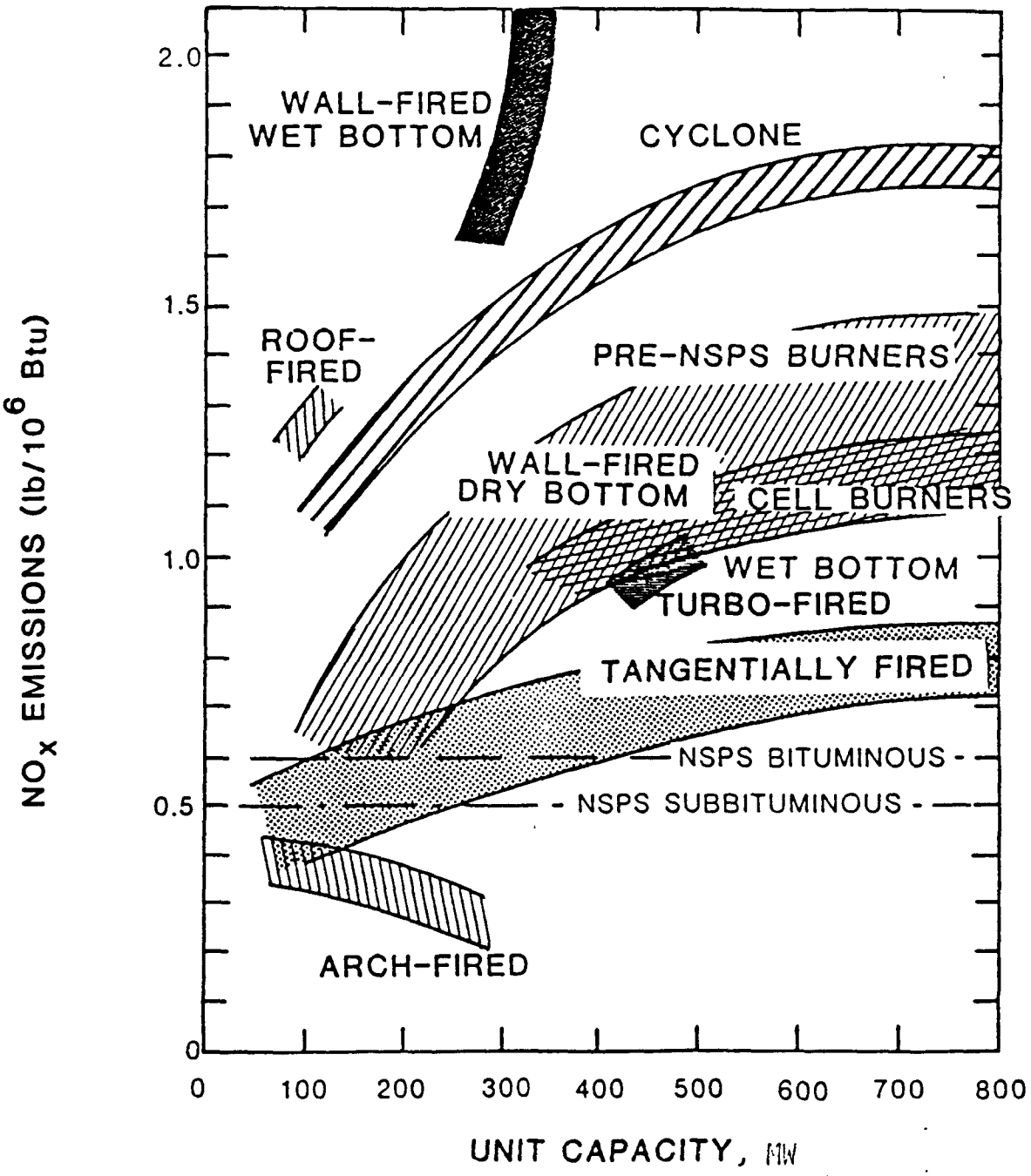


Figure 3-3. Full load NO_x emissions for pre-NSPS coal-fired utility boilers (Miller, 1985)

Table 3-1. NO_x emission factors—coal-fired boilers in the NESCAUM region

Age (yr)	Firing Type	Number of Units	Average Capacity (MWe)	NO_x Emission Factors (lb/MMBtu)	
				This Study	AP-42
0-20[a]	Tangential, dry bottom	0	NA	NA	0.6
	Wall, dry bottom	0	NA	NA	0.6
	Opposed, dry bottom	1	675	0.55	0.6
21-30	Tangential, dry bottom	5	267	0.58-0.70 (0.65)[b]	0.61
	Wall, dry bottom	4	106	0.57-0.80 (0.65)	0.86
	Opposed, dry bottom	2	630	0.84-1.77 (1.33)	0.86
	Cyclone	4	189	1.10-1.41 (1.28)	1.51
	Wall, wet bottom	1	326	2.06	1.39
31-40	Tangential, wet bottom[c]	2	87	0.60-1.64 (1.04)	1.39
	Tangential, dry bottom	13	124	0.45-0.80 (0.64)	0.61
	Wall, dry bottom	8	73	0.42-1.00 (0.89)	0.86
	Wall, wet bottom	2	200	0.44-2.01 (1.20)	1.39
	Vertical, wet bottom	2	66	1.10	1.39
≥41	Tangential, dry bottom	1	53	0.52	0.61
	Vertical, wet bottom[c]	2	64	1.10	1.39
	Wall, dry bottom	1	55	0.79	0.86
	Opposed, dry bottom	2	22	0.83	0.86

[a]Several boilers were converted to coal firing in this time period.
[b]Weighted average; calculated by summing the product of each emission factor in lb/MMBtu and boiler size (MWe) and dividing by the total capacity for that boiler category.
[c]It is not confirmed if these units have slagging furnaces.
NA: No NESCAUM boilers in this category.
Note: To convert to average concentration in ppm at 3 percent O_2 multiply lb/MMBtu by 750.

bottom units with greater than 30 years of service. Significant disagreements, however, are shown for dry bottom boilers in the 21 to 30 years age group and for most wet bottom boilers.

Another important observation is that NO_x levels can vary significantly even within a given source category. For example, the five tangential dry bottom boilers in service for the past 21 to 30 years show a range in NO_x emissions between 0.58 to 0.70 lb/MMBtu. The two dry bottom opposed wall-fired boilers show a range of 0.84 to 1.77 lb/MMBtu. This is indicative of the possible variations in NO_x levels from "similar" units and also that some units may already be controlled. It is important to recognize that percent NO_x reductions are lower from boilers whose current NO_x levels are already low because of existing controls or other site-specific design and operating characteristics. This is because the effectiveness of combustion modifications on existing boilers is limited by operational side effects that can become unacceptable to the safe and reliable operation of the plant when NO_x levels are controlled beyond safety limits. These limits of performance are often very site-specific.

Figure 3-4 plots NO_x emission factors (EF) for the pre-NSPS coal-fired boilers versus boiler capacity. The data illustrate that, for the most part, there does not seem to be any correlation of NO_x with boiler capacity, defined by gross generator output. This illustrates the principal dependency of NO_x on other key boiler design/operating factors, such as heat release rate and firing configuration, and on fuel characteristics, such as volatile matter of coal or fuel nitrogen. Wet-bottom boilers exhibit a full range of uncontrolled NO_x levels.

Table 3-2 summarizes the uncontrolled emission factors for gas- and oil-fired utility boilers. For post-NSPS units, uncontrolled NO_x levels are reported in this study are in the range of 0.21 to 1.05 lb/MMBtu. Only one boiler was reported to exceed 0.5 lb/MMBtu. The averages, weighted according to boiler capacity, ranged from 0.34 lb/MMBtu, for tangential units, to 0.44 lb/MMBtu, for wall-fired boilers and 0.27 lb/MMBtu for opposed-fired boilers (see Appendix B for details). Current NSPS levels are 0.3 lb/MMBtu for oil and 0.2 lb/MMBtu for gas. Average NO_x emissions reported for units in the other age groups are 0.20 to 0.25 lb/MMBtu for tangential units, 0.31 to 0.58 lb/MMBtu for wall-fired units, and 0.28 to 0.65 lb/MMBtu for opposed-fired units. Unless reported directly by the utilities, baseline NO_x emission levels for boilers in the state of New York were calculated based on the emission factors for full boiler load oil- and gas-firing presented in the ESEERCO study (Hunter, 1989) proportioned according to the oil and gas consumption reported in the EIA data base. Unfortunately, separate NO_x emission factors for oil- and gas-firing were not available for all units, therefore some uncertainty in these levels exists. Also, it should be recognized that because emission levels vary with boiler load as well as fuel mix, each boiler will exhibit a particular NO_x emission profile that varies over a day's period, from season to season, and from year to year. Overall, these emission levels indicate that wall and opposed fired units are generally higher emitter of NO_x compared to tangential designs.

Figure 3-5 illustrates current NO_x levels from oil-/gas-fired boilers plotted against boiler capacity in MWe. The boilers are segregated according to dry-bottom, pre- and post-NSPS units, and wet-bottom boilers. It is likely that many of the pre-NSPS boilers are improperly labeled because many were not subject to Subpart D or Da at the time of startup. As with coal-fired boilers, there is no direct relationship between current NO_x levels and boiler capacity. This is again due in part to the influence of boiler design/operating conditions and fuel characteristics, and due to the fact that some units may be already controlled for NO_x.

Table 3-3 summarizes the emission factors for all major boiler/fuel categories in NESCAUM by age group. These factors correspond to the weighted average emission levels presented in Appendices A and B and in Tables 3-1 and 3-2. Table 3-4 groups these data further into only two

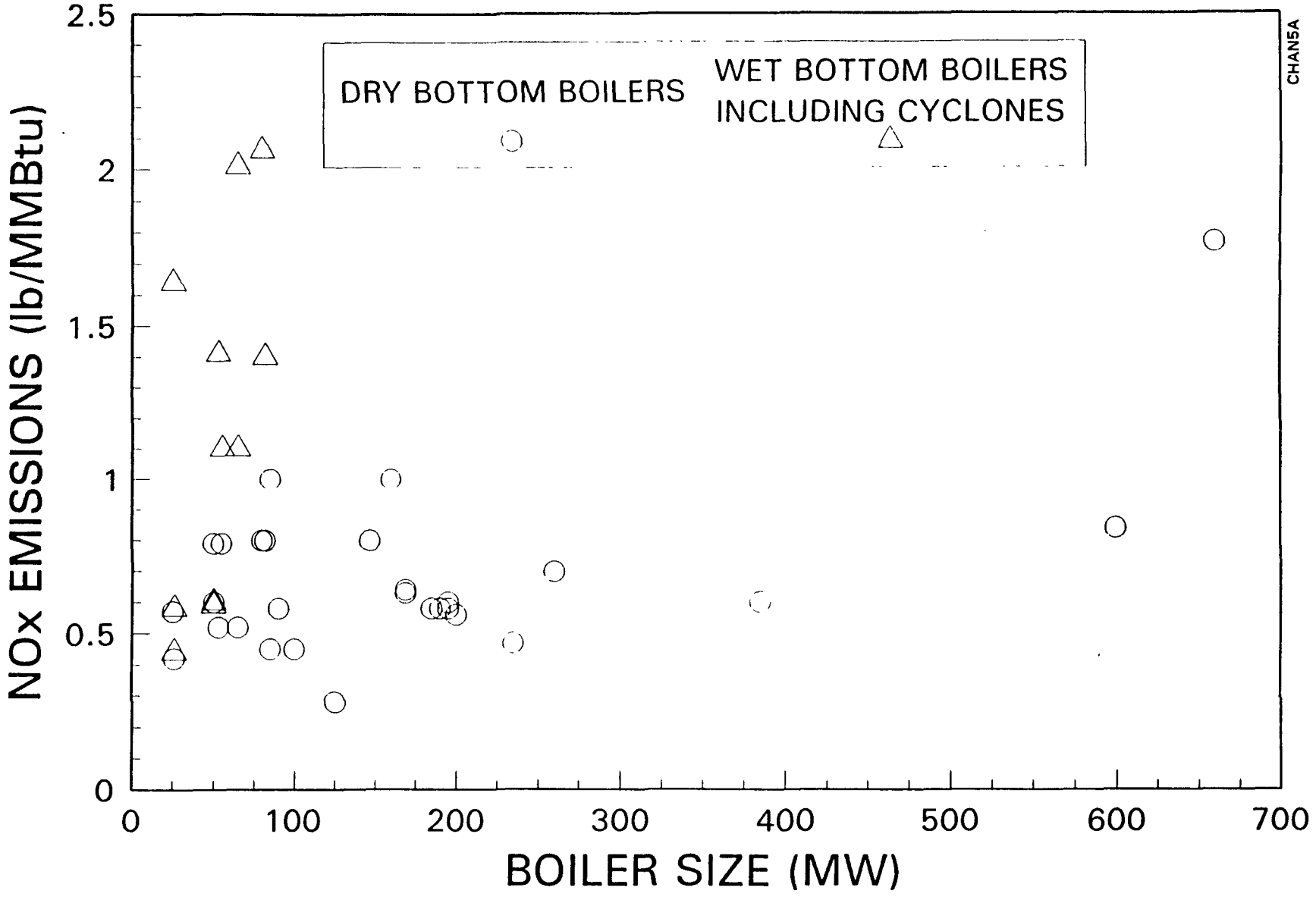


Figure 3-4. NO_x emission levels for pre-NSPS coal units

Table 3-2. NO_x emission factors—oil-/gas-fired boilers in the NESCAUM region

Age (yr)	Firing Type	Number of Units	Average NESCAUM Capacity (MW)	NO_x Emission Factors (lb/MMBtu)	
				This Study	AP-42
0-20	Tangential	10	441	0.22-0.48 (0.34)[a]	0.3
	Wall	9	333	0.21-1.05 (0.44)	0.3
	Opposed	3	515	0.21-0.30 (0.27)	0.3
21-30	Tangential	13	330	0.17-0.34 (0.25)	0.26-0.28
	Wall	3	276	0.29-1.40 (0.52)	0.45-0.52
	Opposed	5	320	0.45-0.90 (0.65)	0.45-0.52
	Cyclone	2	310	0.50-0.68 (0.63)	NA[b]
31-40	Tangential	22	120	0.14-1.36 (0.25)	0.26-0.28
	Wall	18	140	0.28-1.08 (0.58)	0.45-0.52
	Opposed	9	120	0.25-0.31 (0.28)	0.45-0.52
	Cyclone	5	90	0.44-0.50 (0.48)	NA
	Vertical	2	64	0.30-0.70 (0.58)	0.45-0.52
≥41	Tangential	15	80	0.14-0.40 (0.20)	0.26-0.28
	Wall	15	46	0.24-0.48 (0.31)	0.45-0.52
	Vertical	4	46	0.22-0.53 (0.44)	0.45-0.52

[a]Emission factor weighted according to capacity; calculated by summing the product of each emission factor in lb/MMBtu and a boiler size (MWe) and dividing by the total capacity for that boiler category. See Appendix B for detail.
[b]NA = No AP-42 emission factor available for his equipment type.
Note: To convert to average concentration in ppm at 3 percent O_2 multiply lb/MMBtu of NO_x as NO_2 by 790.

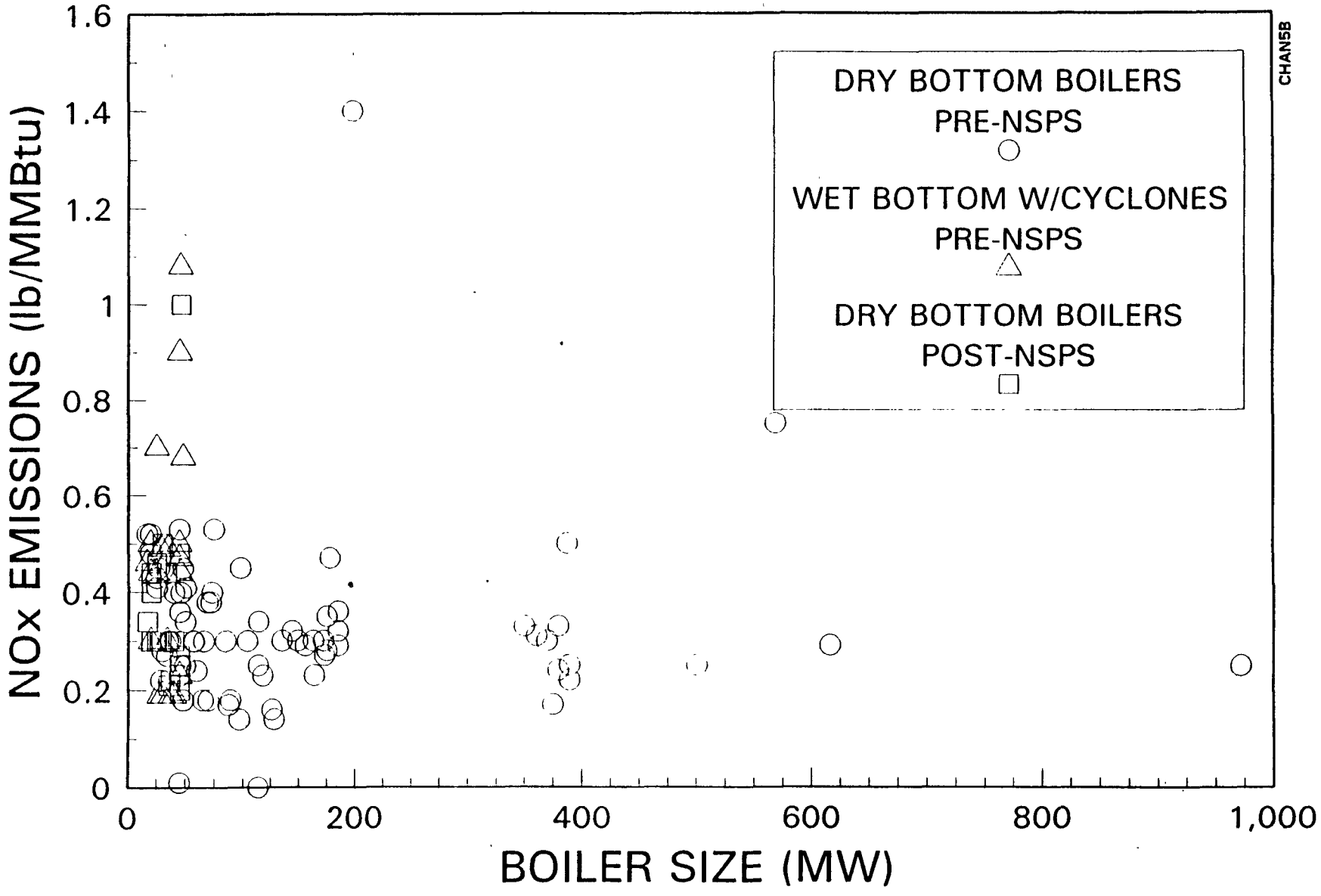


Figure 3-5. NO_x emission levels for oil/gas units

Table 3-3. Average NO_x emission factors for utility boilers in the NESCAUM region

Age (yr)	Firing Type	NO_x, lb/MMBtu	
		PC-Fired	Gas/Oil-Fired
0-20	Tangential	NA[a]	0.34
	Wall	NA	0.44
	Opposed	0.55	0.27
21-30	Tangential	0.65	0.25
	Wall	0.65	0.52
	Opposed	1.33	0.65
	Wall wet bottom	2.06	—[b]
	Cyclone	1.28	0.63
31-40	Tangential	0.64	0.25
	Wall	0.89	0.58
	Opposed	NA	0.28
	Tangential wet bottom	1.04	—
	Wall wet bottom	1.20	—
	Opposed wet bottom	NA	—
	Vertical wet	1.10	—
	Cyclone	NA	0.48
≥41	Tangential	0.52	0.20
	Wall	0.79	0.31
	Opposed	0.83	NA
	Vertical wet	1.10	—

[a]NA = No NESCAUM boilers in this category.
[b]Dashes indicate that this boiler design type is either not available or that reported emission factors for these units have been included in the average for dry bottom boilers.

Table 3-4. Range and average baseline NO_x levels for Pre- and Post-NSPS utility boilers in the NESCAUM region (lb/MMBtu)

Fuel	Firing Type	Pre-NSPS[a]	Post-NSPS
Coal	Tangential	0.45-0.80 (0.60)[b]	NA[c]
	Wall and opposed	0.42-1.77 (0.95)	0.55
	Cyclone	1.10-1.41 (1.28)	NA
	Wet bottom units	0.44-2.06 (1.85)	NA
Oil/gas mix	Tangential[d]	0.14-0.40 (0.24)	0.22-0.48[e] (0.34)
	Wall and opposed[f]	0.24-1.40 (0.52)	0.21-1.051[e] (0.35)
	Vertical	0.22-0.70 (0.52)	NA
	Cyclone	0.44-0.68 (0.60)	NA

[a]All boilers with more than 20 years of service.
[b]Number in parenthesis is the weighted average for all units in the source category.
[c]NA = No boilers with 0 to 20 years of age.
[d]Average for all pre- and post-NSPS units.
[e]Although listed as post-NSPS boilers, high NO_x emitters are not likely subject to NSPS levels because age of boilers in this study, is based on startup date other than the date when the unit was ordered, which is the effective date for NSPS compliance determination.
[f]Average for all pre- and post-NSPS units.

age groups: pre- and post-NSPS boilers. Table 3-4 also shows the full range in reported NO_x emissions for the major figure types. These baseline emission factors are used in this study to determine the range in NO_x controlled levels and cost effectiveness of applicable control technologies. Single wall- and opposed-fired boilers have been combined here because both firing configurations use circular burners and combustion controls that are applicable to both firing configurations. Average PC-unit NO_x emissions for pre-NSPS wall/opposed and tangential designs with more than 20 years of service (only one boiler in the NESCAUM region is post-NSPS) are 0.95 and 0.60 lb/MMBtu. Coal-fired cyclone and other slagging boilers emit, on the average, 1.28 and 1.85 lb/MMBtu. Average NO_x emission levels for gas- and oil-fired boilers are generally in the 0.34 to 0.35 lb/MMBtu range, for post-NSPS tangential- and wall/opposed-fired boilers, and in the 0.24 to 0.52 lb/MMBtu range, for pre-NSPS units. Vertical (down-fired) and cyclone units emit, on the average, 0.52 and 0.60 lb/MMBtu. The range in emission levels shown by individual boilers is significant. Emissions as high as 1.40 lb are indicative of a high furnace heat release rate and high-nitrogen-content fuel. These high emitting gas- and oil-fired units have the potential for the largest net NO_x reductions with combustion controls.

Figure 3-6 plots the baseline NO_x emissions of individual boilers, starting with the lowest emitting unit, versus the cumulative percent capacity of each boiler category of firing types and fuels. For example, approximately 60 percent of the total dry-bottom PC wall-fired (including vertical firing) capacity (2,260 MWe) has a current emission factor of less than 1.0 lb/MMBtu. One unit (shown as the last data point for filled triangles), which accounts for about 30 percent of the existing dry-bottom PC wall-fired capacity, has a reported emission factor of 1.7 lb/MMBtu. Approximately 10 percent of the 3,770-MWe current capacity (370 MWe) for dry-bottom PC wall-fired units has uncontrolled levels of 0.6 lb/MMBtu or less. Significant NO_x reductions from these already low-emitting units should not be anticipated with today's retrofit combustion modifications. For example, a 50-percent NO_x reduction with combustion modifications is very unlikely from boilers emitting 0.6 lb/MMBtu (because 0.3 lb/MMBtu controlled is not deemed reasonable), whereas a 50-percent reduction from units currently emitting more than 1.0 lb/MMBtu is considered more probable but not necessarily achievable in all cases. Nearly all the capacity of tangential PC-fired boilers has an emission factor of about 0.6 lb/MMBtu, nearly twice the current level of most gas-/oil-fired units.

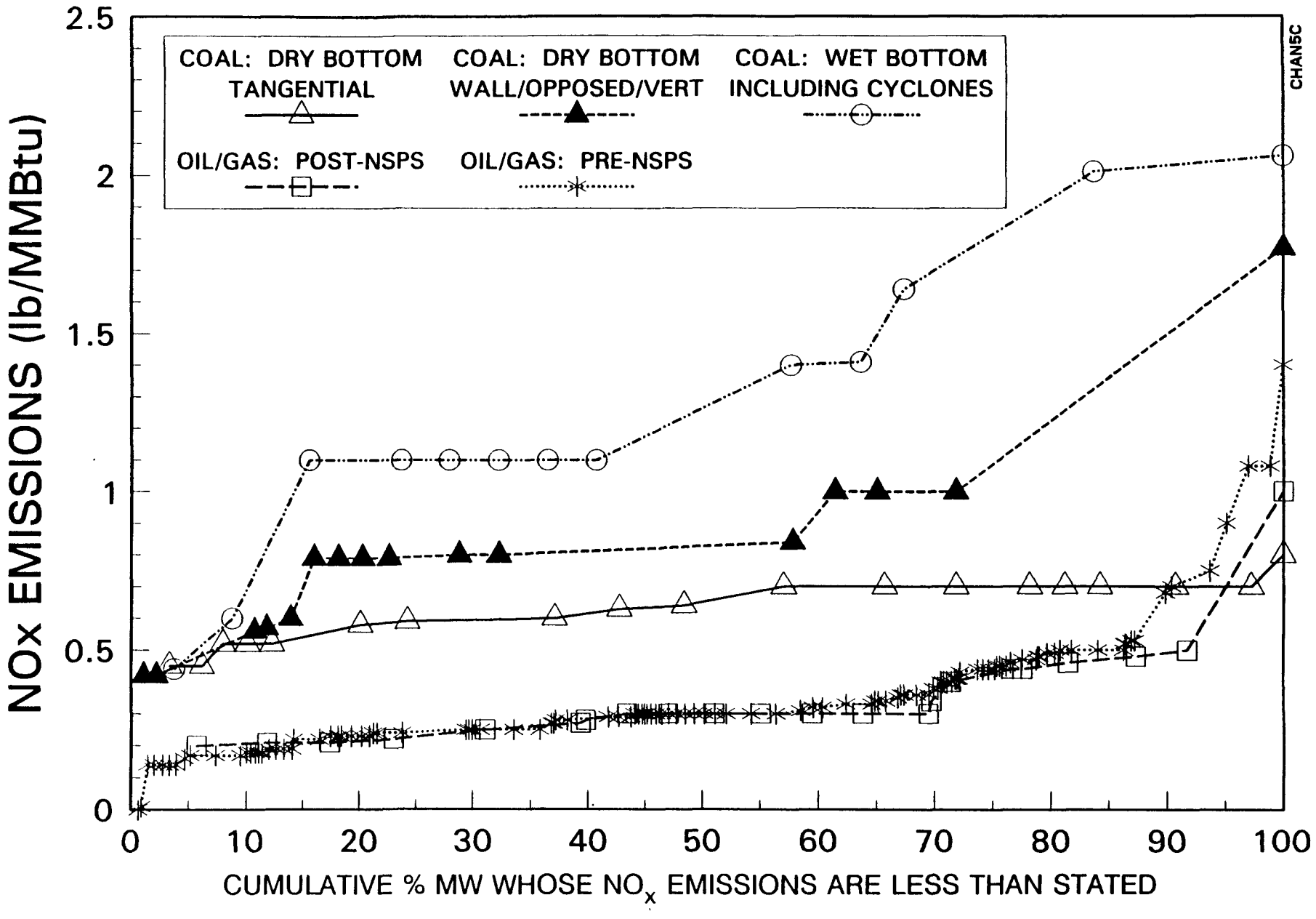


Figure 3-6. Distribution of NESCAUM boilers—NO_x versus capacity

SECTION 4

NO_x CONTROL TECHNOLOGY EVALUATION

NO_x emissions from fossil fuel combustion are caused by the oxidation of fuel-bound nitrogen and the thermal fixation of nitrogen in the combustion air. Although it cannot be predicted with certainty, the amount of fuel nitrogen conversion is known to be a function of many fuel properties and combustion parameters. In coal flames, fuel properties such as nitrogen content, volatile matter, the ratio of fixed carbon to volatile matter, internal moisture, and coal size, among other factors, all affect the quantity of NO_x formed and the degree of control achieved with combustion modifications. As discussed above, boiler furnace designs and operating practices also have a dominant influence on the amount of NO_x generated.

Typically, fuel NO_x in coal and residual (No. 6) fuel oil flames accounts for 60 to 80 percent of the total NO_x formed (Pohl, 1976 and Pershing, 1979). Thus, when burning these fuels the control of fuel NO_x is very important in achieving the desired degree of overall reduction. Control of fuel-air mixing by selective staging of combustion air is the principal combustion modification technique used to suppress fuel NO_x formation in utility boilers. When lighter grade fuel oil or natural gas is burned in boilers, nearly all the NO_x is generated from the high-temperature fixation of free nitrogen in the air. Controlling the peak temperature of combustion and fuel-air mixing is the fundamental approach in reducing NO_x from combustion of "clean" low-nitrogen fuels in boilers. Combustion modifications designed to reduce NO_x emissions from utility coal-, oil-, or gas-fired boilers can result in increased CO and HC emissions and excessive unburned carbon (UBC) in the flyash when coal is burned. Section 7 documents the reported experience to date with CO and HC emissions when NO_x controls are implemented on utility boilers.

There are two basic approaches to the control of NO_x from utility boilers. The first approach focuses on the modification of the combustion process at the burners or in the near burner region of the furnace. In this approach, the fuel and combustion air flowrates and locations are manipulated in such a way to obtain localized regions where N_2 formation is favored over NO_x. For fuel NO_x control from coal and high nitrogen fuel oil flames, the principal technique used is two-staged combustion (TSC) also referred to as off-stoichiometric (O.S.) combustion. TSC is particularly effective in controlling fuel NO_x but also reduces thermal NO_x. In the first stage of this process, the amount of combustion air is suppressed to levels below the theoretical amount required for complete combustion. The lack of oxygen creates reducing conditions that, given sufficient time at high temperature, causes the fuel nitrogen to form N_2 rather than NO. Control technologies using this approach are BOOS, OFA, and LNB. For thermal NO_x control, the principal techniques used are based on reducing the peak flame temperature and/or oxygen concentration. Control technologies that use these approaches are flue gas recirculation (FGR), reduced air preheat (RAP), load reduction, TSC and some LNB designs that utilize high air/fuel ratios in premixed flames with secondary staging. Because of the heavy fuel efficiency penalties, RAP is not viable for retrofit NO_x reduction on utility boilers. For this reason, RAP is not included as a control option for the NESCAUM units.

Low excess air (LEA) is an operational modification that can provide measurable reductions in NO_x. In this report, we have not included LEA as a separate control technology for several reasons. First, LEA is part of good combustion air management that is desirable to minimize dry heat loss. Most utilities attempt to operate their units with LEA to maximize thermal efficiency while ensuring complete combustion. Also, some units require a certain level of excess air to maintain superheater steam temperature. Reduction of excess air from these levels is often not possible without affecting steam temperature. Second, older negative or balanced draft units often have poor combustion air management because furnace air inleakage is difficult to control. Third, LEA generally provides low NO_x reduction efficiency (0 to 15 percent) depending on the degree of available excess air reduction without incurring steam temperature control problems or excessive CO or hydrocarbon emissions. Finally, LEA accompanies the application of low-NO_x combustion hardware such as low-NO_x burners. More importantly, good air/fuel distribution to the various burners is often necessary to optimize excess air while ensuring efficient combustion and adequate cooling of burner equipment. Many PC-fired utility boilers operate with less than optimum air/fuel distribution which can cause high excess air and NO_x emissions and can limit the effectiveness of burner retrofit controls. Although LEA is not considered a NO_x retrofit technology in this report, improved air/fuel distribution to burners along with good fuel preparation can be an important aspect of low-NO_x combustion retrofit controls.

The second approach to NO_x control relies on the destruction of already formed NO_x in the upper section of the radiant furnace or the convective flue gas passages of the boiler. In the reburning process, part of the fuel bypasses the main heat release zone area and is injected above the main burner zone within the furnace. Substoichiometric conditions are attained in the reburning zone. The NO_x formed in the lower burner zone is reduced by radicals such as NH_3, HCN as well as molecular nitrogen. These reactions take place at temperatures exceeding 1,090°C (2,000°F). Additional OFA is then added to combust the residual CO and UHC prior to the combustion products exiting the furnace.

This in-furnace NO_x reduction process is contrasted to flue gas treatment processes which reduce NO_x in the temperature range of about 290 to 1,090°C (550 to 2,000°F). These controls are generally based on the property of NO as an oxidizer for the NH_2^+ specie to produce N_2 and water. This reaction can occur selectively at elevated temperatures (870 to 1,090°C [1,600 to 2,000°F]) without the assistance of a catalyst or at lower temperatures (typically 288 to 371°C [550 to 700°F]) with the assistance of a catalyst. The common reagents used for these techniques are ammonia (NH_3) and urea (NH_2CONH_2), which are used in the SNCR process, and NH_3, which is used exclusively in the SCR process. In some technologies, these NO_x controls are combined with SO_x dry and wet controls to reduce these two pollutants simultaneously. Additional FGT techniques have been investigated, but for the most part, the most common NO_x control technologies applicable to some units in the NESCAUM boiler inventory are the SNCR and SCR processes.

Recent regulations in Germany and Japan have necessitated the use of an FGT process, primarily SCR, to achieve some of the lowest NO_x standards in the world. In the United States, the control of NO_x from power plant coal-,oil-, and gas-fired boilers has focused on the use of combustion modification techniques developed and implemented over the past two decades. Although in Europe, particularly Germany, and Japan both SNCR and SCR have been applied with success, these countries also rely primarily on the application of combustion modifications to achieve the bulk of necessary NO_x reductions. Only when the capabilities of these lower cost approaches have been exhausted, are FGT controls generally considered.

The following sections discuss the commercially available retrofit NO_x controls that are applicable to the utility boilers in the NESCAUM Region and the documented experience in NO_x

reduction performance and retrofit requirements. Although, these NO_x reduction performance and controlled levels span a wide range of values, actual NO_x reductions that are attainable at any power plant in NESCAUM are often a function of many site-specific considerations coupled with the degree of combustion equipment upgrades that are included with the retrofit. Therefore, the information presented in this section on applicability and performance of NO_x retrofit controls in offered as general guidelines for the "typical" boiler within a given fuel/design and age category and that the information does not necessarily apply to any specific unit in NESCAUM. Site-specific analyses are recommended to ascertain whether the emission levels cited in this report can be achieved by any particular site.

Schematics of many of the controls are included in Appendix C. Reports of NO_x reduction performance and controlled levels attained in full-scale retrofits are summarized in Appendix D. Controlled emission levels and control efficiencies reported in Appendix D are used as the basis for estimating NO_x reduction performance from average baseline levels in the NESCAUM region and to estimate the range in controlled emission levels.

4.1 COMBUSTION CONTROLS FOR COAL-FIRED BOILERS

Table 4-1 summarizes NO_x reduction performance, application, and anticipated equipment modifications for retrofit NO_x combustion modification controls for coal-fired utility boilers. Percent NO_x reductions and controlled levels listed in the table reflect performance levels reported in the literature. Appendix D details this reported performance. These reduction efficiencies were applied to average baseline NO_x levels for the various boiler designs (Tangential [T], wall-fired including opposed firing [W], slagging or wet-bottom [S], and cyclone [C]) and age groups (pre-NSPS and post-NSPS) reported in Table 3-4 to arrive at estimates of controlled NO_x emission estimates for NESCAUM units.

Estimates of lowest NO_x levels achievable with combustion controls are in the range of 0.35 to 0.55 lb/MMBtu (260 to 420 ppm at 3 percent O_2), for pre-NSPS dry-bottom wall-fired boilers, and 0.30 to 0.45 lb/MMBtu, for pre-NSPS dry-bottom tangential boilers. As discussed later, the current experience with retrofit of LNB+OFA on wall-fired boilers is minimal. Therefore, these LNB+OFA estimates are based on a limited performance data set that can prove optimistic. Also, the level of control that will be attained will be influenced by the furnace size, the fuel type, and the ability to maintain operational flexibility with UBC, waterwall corrosion, and steam temperature control in check. The current data base on LNB retrofit alone, however, is more extensive, supporting NO_x reductions of 35 to 55 percent on individual pre-NSPS boilers with controlled levels reported in the range of 0.45 to 0.60 lb/MMBtu. Again, as explained later, the more aggressive reductions are more likely from boilers with high uncontrolled levels, burning favorable medium- to high-volatile coals, undergoing extensive upgrade of existing equipment, operating within a narrow load range, and monitored under short-term test conditions.

No attempt was made in this study to differentiate or correlate the NO_x reduction performance of these controls according to other key boiler design and operating variables such as furnace or burner zone liberation rate (BZLR, Btu/hr-ft^2), volumetric heat release rate (VHRR, Btu/hr-ft^3), excess combustion air, or boiler load. NO_x reduction performance of combustion modification controls is influenced by these and other design and operating variables. Typically larger percent NO_x reductions apply to boilers with higher baseline NO_x levels and boilers burning high-volatile-content coals.

All these combustion controls utilize staging of combustion air, fuel, or both for NO_x reductions estimated to range from 15 to 65 percent. The lowest reduction potential is for OFA

Table 4-1. Combustion controls for coal-fired utility boilers

Control Technology	Percent NO_x Reduction and Controlled NO_x Levels (lb/MMBtu)[a]		Applicable Boiler Designs	Anticipated Equipment Modifications and System Upgrades
	Pre-NSPS	Post-NSPS[b]		
OFA or advanced overfire air (AOFA)	15 to 30 (0.40 - 0.50) T 15 to 25 (0.70 - 0.80) W	15 to 25 (0.40 - 0.50) W	Some wall- and T-fired dry bottom boilers with large furnaces	Installation of OFA ducting and ports with waterwall panel modification. Addition of OFA airflow dampers for improved distribution. Installation of curtain air for some designs. Asbestos removal for older units. Emission monitoring system and OFA damper control.
LNB (T-fired units equipped with CCOFA)	25 to 30 (0.40 - 0.45) T 35 to 55 (0.45 - 0.60) W	20 to 30 (0.40 - 0.45) W	Most wall- and T-fired boilers, except slagging units	Installation of new burners and scanners. Replacement of burner zone tubing panels in some units. Burner/pulverizer control system upgrade. Replacement of coal piping, hangers, valves, igniters, viewports. Structural modifications and platforms. Windbox modifications and mill upgrades. CEM system retrofit.
LNB+OFA (AOFA for W-boilers; SOFA for T-units)	30 to 50 (0.30 - 0.45) T 40 to 60 (0.35 - 0.55) W	35 to 45 (0.35 - 0.40) W	Some wall- and T-fired boilers exclusive of high heat release rate units	All equipment upgrades and replacements cited above, plus: replacement of (T) or modification (W) of windbox. Replacement of combustion air control system. Fan and pulverizer modifications. Installation of OFA ports and waterwall panel modifications.
Reburning with natural gas (NGR) or coal. (requires OFA for all retrofits)[c]	45 to 60 (0.50 - 0.70) C,S 40 to 60 (0.25 - 0.35) T 45 to 60 (0.40 - 0.50) W	40 to 55 (0.25 - 0.35) W	All boilers, but technology targeted primarily for cyclone (C) and slagging (S) units	Installation of reburning burners and OFA ports. Replacement of tube wall panels. Piping ductwork to reburn burners and OFA ports. Burner/combustion control system. Gas fuel substation for NGR or pulverizer installation for coal reburn on cyclones. FGR ducting, fan, and CEM system.

W = Wall-and opposed-fired boilers; T = Tangential (corner)-fired boilers; C = Cyclone boilers; S= boilers with high heat release slagging furnaces.

[a]Controlled levels are based on estimated reduction performance and weighted average baseline levels reported in Table 3-4.

[b]Only one boiler in the NESCAUM region is listed as a post-NSPS-design unit. Controlled emission levels are from current baseline of 0.55 lb/MMBtu for the opposed wall-fired boiler.

[c]Reburning is offered by major boiler manufacturers in Japan and the United States, but no commercial experience exists in the United States. Several demonstration and validation projects are ongoing and reporting successful results and pointing to the commercial viability of the technology.

which has some important limitations in the degree of combustion staging and first stage stoichiometries. Because OFA utilizes a large portion of the entire firebox volume to obtain the needed separation between first and second stage, unburned carbon in the flyash and CO emissions can be significant if excessive (greater than 25 percent) OFA is utilized, especially when burning high-rank bituminous coals. Waterwall corrosion is also a significant concern in the retrofit of OFA for high-sulfur coal- and oil-fired boilers. The potential for increased corrosion rate can be reduced by several approaches. One such approach for wall-fired boilers uses curtain air introduced from the furnace hopper so that an oxidizing environment is maintained near the waterwalls. For tangential boilers, some of the combustion air is diverted away from the center of the furnace toward the waterwall to prevent exposure of furnace tubes to reducing conditions that cause H_2S formation.

Because of recent advances in LNB technologies offered by most major boiler manufacturers, LNB is often the preferred low-NO_x option for both new and retrofit units. One technology vendor has claimed that when combined with OFA, LNB can reduce NO_x from coal-fired utility boilers to levels approaching 160 ppm (0.21 lb/MMBtu) (Vatsky, 1991). However, full-scale experience at such low NO_x levels is limited, and has shown significantly more modest performance. Reburning with natural gas or coal can achieve significant NO_x reductions, reported, as high as 65 percent for pre-NSPS wet-bottom and cyclone units. Although applicable to most boiler designs, reburning is primarily targeted for the cyclones and wet-bottom boilers that are difficult to control by other combustion methods. Commercialization of this promising technology in the U.S. awaits the results of long-term testing at the five ongoing demonstrations described in Section 4.1.4.

Table 4-2 compares controlled NO_x levels estimated for the NESCAUM major boiler categories of pre-NSPS vintage with controlled NO_x levels reported in the literature. As the footnote indicates, details of these reported controlled levels are given in Appendix D. The comparison is made with data reported on a short-term or long-term basis and with two broad categories of coal type: low volatile with an FR equal or greater than 1.5, and medium to high volatile coal with an FR lower than 1.5. As discussed earlier, these are important distinctions because they affect the NO_x levels that can be achieved and maintained by a utility boiler over a specified period of time under routine load dispatch, fuel mix, and operating practices. Long-term refers to data reported in the literature averaged over a 30-day period or longer. Some important aspects of this comparison are discussed below.

NO_x controlled levels estimated for NESCAUM T-fired boilers following the retrofit of LNB+SOFA are in the range of 0.30 to 0.45 lb/MMBtu. The upper level of this range, 0.45 lb/MMBtu, compares favorably with NO_x levels reported with low volatile coals under long-term operation. However, the lower level in the range, 0.30 lb/MMBtu, compares more favorably with higher volatile coals under either short or long-term performance evaluation. As noted earlier, lower NO_x levels under staged combustion conditions are more likely with high volatile coals than with higher rank low volatile bituminous coals. Furthermore, long-term performance is generally more difficult to attain because it encompasses boiler operation under a variety of boiler loads and other operating conditions that can significantly affect NO_x emissions. Short-term testing is normally taken to mean boiler operation under well controlled and supervised operation over a period of a few hours.

The controlled NO_x levels estimated for LNB+OFA for single- or opposed wall-fired boilers range between 0.35 to 0.55 lb/MMBtu. This range corresponds to a drop of about 40 to 60 percent from the average baseline level of 0.95 lb/MMBtu. The reported data for this type of low-NO_x application are sparse as will be discussed later in this section. However, it is clear that the upper

Table 4-2. Estimates for average controlled levels for pre-NSPS NESCAUM coal-fired boilers

Boiler Type	Applicable Control	Reported Control Performance (%)	Controlled NO_x Levels (lb/MMBtu)				
			Estimate, This Study[a]	Reported in the Literature[b]			
				Low Volatile Coals		Medium to High Volatile Coals	
				Short Term	Long Term	Short Term	Long Term
Tangential	SOFA	15-30	0.40-0.50	NA[c]	NA	0.41	0.45
	LNB	25-30	0.40-0.45	0.40	0.44	0.32-0.35	0.41
	LNB+SOFA	30-50	0.30-0.45	0.38-0.40	0.44-0.45	0.25-0.33	0.32
	NGR	45-60	0.25-0.35	0.20-0.33	0.27	NA	NA
Wall and Opposed	OFA (AOFA)	15-25	0.70-0.80	0.80	0.92	NA	NA
	LNB	35-55	0.45-0.60	0.40-0.53	0.46-0.64	0.33-0.50	0.46
	LNB+AOFA	40-60	0.35-0.55	0.54	NA	NA	0.33
	NGR	55-65	0.35-0.45	NA	NA	NA	NA
Cyclone and Other Wet Bottom	Reburning with OFA	45-65	0.45-0.70	0.40	NA	0.33-0.47	NA

[a]These levels were calculated based on percent NO_x reduction range reported in the literature applied to average baseline NO_x levels shown in Table 3-4.

[b]These controlled levels were reported in the literature. Further details and references can be found in Appendix D. Low volatile coals with FR greater than 1.5.

[c]NA = No data available to support performance estimated in this study.

range of 0.55 lb/MMBtu compares favorably with short-term data taken at one facility burning eastern bituminous coal, recently reported by Southern Company Services, Inc. (Sorge, 1992). The lower end of the range compares with a level obtained at one facility burning high volatile coal. As will be discussed later, much more experience exists with LNB only for wall-fired boilers than with LNB+OFA.

The following sections provide a brief summary of the status of these technologies and reported retrofit performance.

4.1.1 Overfire Air (OFA)

OFA was one of the first control technologies evaluated by boiler manufacturers and regulated utilities. OFA, by itself, generally offers modest NO_x reductions with potential for significant operational impacts. In this approach, OFA ports are installed in the furnace above the top row of burners. The existing windbox is either extended or a separate OFA ducting is installed to provide secondary OFA to these new upper furnace ports.

For pulverized-coal units, OFA is applicable to both corner-fired and wall-fired (front and opposed) boilers. For tangential boilers, ABB-CE distinguishes OFA between two configurations: CCOFA and SOFA (Towle, 1991). A third OFA configuration combines the two OFA systems used under advanced low-NO_x burner configurations discussed in the next section. OFA is not applicable to cyclone boilers and other slagging furnaces because combustion staging will alter the heat release profile significantly changing the slagging rates and properties of the slag. Many of the post-NSPS tangential boilers come equipped with CCOFA ports. Newer OFA designs that increase the penetration of air into wall-fired furnaces for improved second-stage burnout under deeper staging are often referred to as AOFA, and have separate ports with a separate windbox located above the main burner windbox.

There are two principal design requirements for the retrofit of OFA ports in an existing coal-fired boiler furnace. First, there must be sufficient furnace volume above the top row of burners to provide adequate residence time of the first stage gases for NO reduction to N_2 and adequate residence time of the second stage gases prior to exiting the furnace to achieve carbon burnout (Lisauskas, 1988; LaRue, 1990). Often, sufficient distance between the top burner and the furnace exit is not available to achieve the ideal 0.8-second residence time (Lisauskas, 1988). The amount of residence time needed for maximum NO_x reduction is dictated by overall kinetic rates of reactions at the furnace temperature, and the gas composition. This often necessitates a compromise in NO_x reduction performance.

The second requirement is that the OFA must be effectively mixed with the first stage gases to ensure complete combustion. This effective mixing cannot be simply achieved by high rate of OFA addition since low O_2 levels must be maintained to minimize the dry gas heat loss from the boiler. The high OFA velocity needed for good mixing requires installation of several ports, which can affect the structural integrity of the furnace. For example, access to the OFA injection location may require the reconfiguration of the boiler structural support. Also, penetration into the furnace, due to the installation of air ports, may result in structural weakness of the boiler tube panels.

Generally, the OFA ports are designed to allow 20 to 30 percent of the total air injected in the furnace (Lisauskas, 1987; LaRue, 1990; Wilson, 1990). There are practical limitations to this quantity of OFA. First, excessive OFA can result in an increase in unburned carbon (UBC) in the flyash and increased emissions of CO, both are measures of loss in combustion efficiency. Data on reported loss in combustion efficiency are presented in Section 7. Excessive UBC in flyash can also

affect the ability to sell flyash for use in cement production. For several utilities that currently follow this practice, the inability to continue to sell the flyash would result in a significant financial penalty. Increasing coal fineness can offset the effect of OFA on UBC. But increasing fineness can require replacing the pulverizers or making modifications to the classifiers. Modification to classifiers can reduce the capacity of the existing mill resulting in a derate of the boiler. Second, excessive OFA can cause too low first stage stoichiometries which can lead to localized reducing conditions near furnace waterwalls with increase in waterwall slagging, corrosion and tube failure rate. Curtain air is used in some boilers to counter the potential detrimental corrosion effect of OFA or other air staging techniques.

Installation of OFA requires retrofit of OFA ports, modification of the combustion air ducting, addition of airflow dampers to control the amount of air in the primary and secondary combustion stages, and improved combustion control system. The retrofit of OFA ports necessitates the replacement of waterwall panels. The OFA ports for tangential units are typically equipped with directional vanes that, along with burner tilt, are used for better control of combustion and superheater steam temperature at variable boiler loads.

Retrofit of the technology generally results in a loss in combustion efficiency due to increased unburned carbon in the flyash and increase in excess oxygen level. For example, efficiency loss with 27 percent OFA on one retrofit tangential boiler was reported at 0.4 percent (Thompson, et al., 1989) due to an increase of 1 percent in excess oxygen. Additional efficiency loss due to unburned carbon in the flyash could further decrease the overall thermal efficiency. For example, a 2-percent increase in UBC for a 13,000 Btu/lb coal with 14 percent ash translates into a 0.4-percent loss in combustion efficiency and an equivalent increase in fuel consumption. Carbon burnout is sensitive to changes in combustion conditions, and increases in UBC due to staged combustion, LEA, or LNB are likely. For some older boilers, however, these losses in efficiencies could be partially offset by improvements in overall combustion air management and air infiltration. OFA alone frequently does not offer sufficient NO_x reductions to be a viable NO_x control technique for some eastern bituminous coals because of negative impacts of excessive UBC and potential accelerated furnace corrosion.

The NO_x reduction efficiency for OFA is estimated to range between 15 and 30 percent for pre-NSPS boilers. However, there is little full-scale retrofit experience to support these reduction efficiencies. Recent tests at the Hammond Unit 4 show NO_x reduction efficiencies of 18 percent over the long term and up to 30 percent for short-term tests at certain boiler loads (Sorge, 1992). Post-retrofit NO_x levels from these boilers are anticipated to be in the range of 0.40 to 0.50 lb/MMBtu, for T-fired units, and 0.70 to 0.80 lb/MMBtu, for wall-/opposed-fired units. These controlled levels are calculated based on the average baseline emissions of 0.60 lb/MMBtu for pre-NSPS T-fired dry-bottom boilers and 0.95 for pre-NSPS W-fired dry bottom boilers; see Table 3-4, and estimated reduction efficiencies in Tables 4-1 and 4-2. Boilers with significantly higher uncontrolled NO_x will likely not achieve these targets. NO_x reductions of 0.40 to 0.50 lb/MMBtu are estimated for the only PC wall-fired post-NSPS boiler in the NESCAUM region with a current baseline of 0.55 lb/MMBtu. These estimates are highly speculative because no data are available to confirm the ability of post-NSPS boilers to achieve these NO_x levels without retrofit of newer generation burners.

4.1.2 Low-NO_x Burners (LNB)

Since the first application of OFA in the 1970s, the major boiler manufacturers in the U.S. and Japan have realized that combustion staging with OFA ports is not the ideal approach to NO_x control from pulverized coal flames. The NO_x reduction potential of OFA was initially limited by

several factors. Under staged combustion a significant fraction of the fuel NO_x is from char nitrogen oxidation. By operating the entire lower burner zone under substoichiometric conditions, the local temperature is also reduced. This lower temperature tends to liberate less of the nitrogen in the first stage, consequently carrying more to the second stage where it can be oxidized to produce NO_x. Furthermore, staging creates the potential for localized corrosion and increased carbon carryover that can be a significant problem to boiler operators and utilities. Installation of OFA ports requires changes to pressure parts. The compactness of the boilers furnaces built in the 1960s was another disincentive to further OFA development because of the space limitations imposed for retrofit applications. Extending the furnace or derating for additional gas residence time with OFA applications can present a potential remedy to compact furnaces. However, furnace modification and derating are costly options.

All major utility boiler manufacturers, here and abroad, have successfully developed LNBs that can be used in new and retrofit applications. The controlled mixing of combustion air and pulverized coal is at the heart of all tangential and circular LNB designs. By imparting greater separation of fuel and air in the near-burner region, LNBs take advantage of combustion air staging and lower peak temperatures that result from larger flame volumes to suppress both fuel NO_x and thermal NO_x formation. However, by far the greatest design accomplishment of LNB technology has been the suppression of fuel NO_x via well-controlled mixing while maintaining satisfactory combustion efficiency, heat release profile, and operational flexibility. A detailed engineering analysis by experienced equipment vendors and site personnel is necessary in order to match off-the-shelf LNB technology to existing boiler equipment, fuel characteristics, and operating requirements. Although most LNB retrofits have been successful, compatibility between specific NO_x targets and satisfactory boiler operation must rely on detailed site-specific analyses.

The following two subsections briefly discuss the LNB technologies offered for tangential and wall-fired boilers.

4.1.2.1 LNB for Tangential-Fired Boilers with CCOFA

ABB-CE improved on its inherently low-NO_x corner-fired burner design by developing the Low-NO_x Concentric Firing System (LNCFS). ABB-CE offers three levels of LNCFS equipment for retrofit on existing T-fired boilers. NEI-International Ltd., of Europe, also offers low-NO_x burners for T-fired boilers. Each of these three configurations offers CCOFA. LNCFS II and LNCFS III also offer SOFA above the main windbox, without CCOFA under LNCFS II configuration. All three design types divert some of the combustion air toward the walls of the furnace, further reducing the amount of combustion air in the center of the furnace while providing some protection against waterwall corrosion. Combined with clustering of coal and air nozzles, various degrees of combustion staging can be realized while protecting waterwalls and achieving efficient combustion. Appendix C provides details of these LNCFS configurations.

This section is limited to a discussion of LNCF Level I configuration because it is the only one of the three that does not come equipped with SOFA. LNCFS II and LNCFS III, together with other LNB systems that also come equipped with SOFA, are discussed in Section 4.1.3. Although SOFA is an integral part of the tangential firing configurations, we have arbitrarily selected to discuss these combined technologies under the heading of LNB+OFA to compare various wall- and tangential-technologies that use OFA introduced at a significant distance above the main burner zone.

The retrofit experience with LNCFS I is minimal. Only two domestic applications have been documented to date. The first of the LNCFS I applications was at the Utah Power and Light

Hunter 2 (Kokkinos, 1985). This post-NSPS 420 MWe boiler burning western bituminous coal achieved a 30-day average NO_x reduction of 33 percent to 0.41 lb/MMBtu. More recently, LNCFS I is being evaluated at the Georgia Power's Lansing Smith 2 (Hardman, EPRI 1992; ICTTE, 92). As of this writing, test data are not available for Lansing Smith 2. The performance of this pre-NSPS boiler burning bituminous coal will be more representative of the anticipated performance for this burner system for NESCAUM T-fired units. ABB-CE projects LNCFS I NO_x reduction performance in the range of 25 to 32 (Grusha, 1991). In Europe, LNCFS offered by NEI-International Ltd. was retrofitted on Fiddlers Ferry Unit 1 of Powergen in England. The boiler has routinely achieved 35-percent NO_x reduction throughout the boiler load range, with improved furnace conditions (Jones, 1992).

4.1.2.2 LNB for Wall-Fired Boilers

For wall-fired boilers, single wall or opposed burner configurations, FWEC, B&W, and Riley Stoker in the U.S., Babcock Hitachi (BHK) of Japan, and Burmeister & Wain Energy (BWE) of The Netherlands have introduced and installed several LNB with proven NO_x reduction performance of about 35 to 55 percent. Table 4-3 lists a number of LNB retrofits for wall-fired boilers. The information includes both pre-NSPS and post-NSPS units as well as reported performance for short and long term tests with a variety of coals and LNB designs. FWEC provides two commercial LNB designs: the CF/SF and IFS. Retrofit of these burners have shown a range in difficulty of retrofit and NO_x reduction performance. Although several retrofits have been successfully implemented, more recent applications at GPC Hammond Unit 4 (Sorge, 1992), PENELEC Homer City Unit 2 (Manaker, 1992), and PSC Cherokee Unit 3 (Hunt, 1992) have illustrated both the sensitivity of operation and NO_x performance to the adequate control of air/fuel distribution, combustion air velocity and cooling, primary air/fuel ratio, and pulverizer performance.

Figure 4-1 illustrates FWEC reported performance of the CF/SF and IFS designs offered for wall-fired boilers. The plot is for NO_x levels achieved with FWEC LNB versus burner zone liberation rate, a measure of the combustion intensity in the near burner zone. The plot shows that generally, the higher the liberation rate, the higher the uncontrolled and controlled NO_x levels. The black arrows describe the reduction in NO_x achieved from full-scale boilers with the retrofit of the CF/SF burner without the use of OFA. The plot also shows that performance of the CF/SF LNB was generally projected to be about 0.40 lb/MMBtu and that the newer IFS design might be capable of controlled levels of 0.25 lb/MMBtu based on these limited results. However, recent applications of both these burner types have not realized these performance levels, as illustrated in Table 4-3.

The B&W LNCB burner is designed for minimum retrofit cost to existing cell burner boilers. The current LNCB demonstration is being conducted under DOE's CCT demonstration program. The more commercial B&W LNB design, the DRB-XCL burner, has seen relatively good success on at least two boilers. Other LNB retrofits include several foreign designer by Babcock Energy, BWE, and BHK. Because the BWE burners do not use a common windbox design, as is the practice with U.S. boilers, the retrofit of this type of burner will require greater equipment modifications. ABB-CE also offer LNB for wall-fired boilers. More recently, FWEC has also been evaluating LNB prototypes for T-fired units.

The retrofit of LNBs to existing units often require no changes to pressure parts, meaning that most LNB retrofits are possible with minimal modifications to the waterwall, significantly reducing retrofit cost (Vatsky, 1991; Lisauskas, 1987). Significant modifications are often needed to the windbox, however, for improved air distribution with changes in the fuel ducting, and pulverizer adjustments. Some LNB designs have only minor increases in pressure drops necessitating minor changes to the combustion air fans to maintain furnace draft. Excessive

Table 4-3. Partial list and performance of wall PC-fired LNB applications

Burner Type	Manufacturer	Retrofit Applications	Coal Type	Reported Performance	References
CF/SF	FWEC	U.S. Applications:			
		• GPC Hammond 500 MWe Unit 4 (Pre-NSPS)	E. Bituminous	30-day average 48% reduction to 0.64 lb/MMBtu, 53 percent reduction to 0.53 lb/MMBtu averaged over 94 days of testing. Burner problems due to poor air/fuel flow	Sorge, 1992
		• MP Pleasant 650 MWe Unit 2 (Post-NSPS)	E. Bituminous	Short-term performance showed 60 percent reduction to 0.41 lb/MMBtu	Vatsky, 1989
		• MP Harrison 500 MWe Unit 3 (Pre-NSPS)	E. Bituminous	Short-term tests reported NO_x reduction to 0.5-0.6 lb/MMBtu from 1.10 lb/MMBtu or up to 55% reduction. Several burner failures	Vatsky, 1989
		• APS Four Corners 800 MWe Unit 4 (Pre-NSPS)	W. Subbitumin.	Short-term data shows 55% reduction at full load to 0.45 lb/MMBtu. 0.5 lb/MMBtu at 1/2 load. No negative impacts reported	Lu, 1991
		Foreign Applications:			
		• TPC Hsin-Ta 500 MWe Unit 1 (Post-NSPS)	Various FR = 1.15 to 1.85	34% reduction from 0.7 lb/MMtu to 0.464 lb/MMBtu over long term. No reported impacts.	Vatsky, 1991
		• San Juan 360 MWe Unit 1 (Post-NSPS)	W. Subbitumin.	60% reduction reported on short-term tests to 0.45 lb/MMBtu	Vatsky, 1985
IFS	FWEC	U.S. Applications:			
		• PSC Cherokee 160 MWe Unit 3 (Pre-NSPS)	W. Bituminous	Short-term 47% reduction at full load to 0.5 lb/MMBtu. Retrofit problems. Optimization underway	Hunt, 1992
		• TVA Colbert 200 MWe Unit 3 (Pre-NSPS)	E. Bituminous	Achieved controlled level of 0.47 lb/MMBtu over long term	Manaker, 1992
		• TVA Johnsonville 150 MWe Unit 8 (Pre-NSPS)	E. Bituminous	Preliminary tests showed 53% reduction to 0.45 lb/MMBtu	Manaker 1992
DRB-XCL	B&W	U S Applications:			
		• SCS Gaston 250 MWe Unit 2 (Pre-NSPS)	E. Bituminous	Short-term 46% reduction to 0.4 lb/MMBtu at full load and 0.3 lb/MMBtu at 20% load	Hardman, 1992
		• Ohio E Edgewater 100 MWe Unit 4 (Pre-NSPS)	E. Bituminous	Short-term tests showed 43% reduction to 0.43 lb/MMBtu at full load. Limited performance due to poor air/fuel distribution	LaRue, 1989
LNCB	B&W	U S Applications:			
		• DP&L Stuart 605 MWe Unit 4 (Pre-NSPS)	E Bituminous	Short term 55% reduction reported to 0.526 lb/MMBtu. No negative operational impacts.	Laursen, 1992

Table 4-3. Partial list and performance of wall PC-fired LNB applications (concluded)

Burner Type	Manufacturer	Retrofit Applications	Coal Type	Reported Performance	References
Mark III	Babcock Energy	Foreign Applications: • CEGB Drax 660 MWe Unit 6	LowVol FR = 1.53	Short-term 54% reduction to 0.51 lb/MMBtu at full load	King, 1991
		• CEGB Ratcliffe Unit 2	U.K unspecified	Short-term reported 38% reduction to 0.51 lb/MMBtu at full load with some flame impingement	Jones, 1992
HTNR	BHK	Foreign Applications: • EPZ Maas 166 MWe Unit 5	MedVol FR = 1.49	36% reduction reported long-term to 0.56 lb/MMBtu. No impact on UBC.	VanDerKooji, '91
CCV	Riley Stoker	U.S. Applications: • PSI Wabash 125 MWe Unit 5 (Pre NSPS)	E. Bituminous	Reported >50% reduction to 0.45 lb/MMBtu with operational improvement via equipment upgrade	Penterson, '91

CCV: Combustion Controlled Venturi
LNCB: Low NO_x Cell Burner
HTNR: Hitachi NO_x Reduction
CF/SF: Controlled Flow/Split Flame
IFS: Internal Fuel Staging
CEGB: Central Electricity Generating Board

B&W: Babcock & Wilcox
BHK: Babcock Hitachi K.K.
FWEC: Foster Wheeler Energy Corporation
BWE: Burmeister & Wain Energy
SCS: Southern Company Services
PSI: Public Service of Indiana

GPC: Gulf Power Company
PSC: Public Service of Colorado
MP: Monongahela Power
TVA: Tennessee Valley Authority
APS: Arizona Public Service
DP&L: Dayton Power & Light

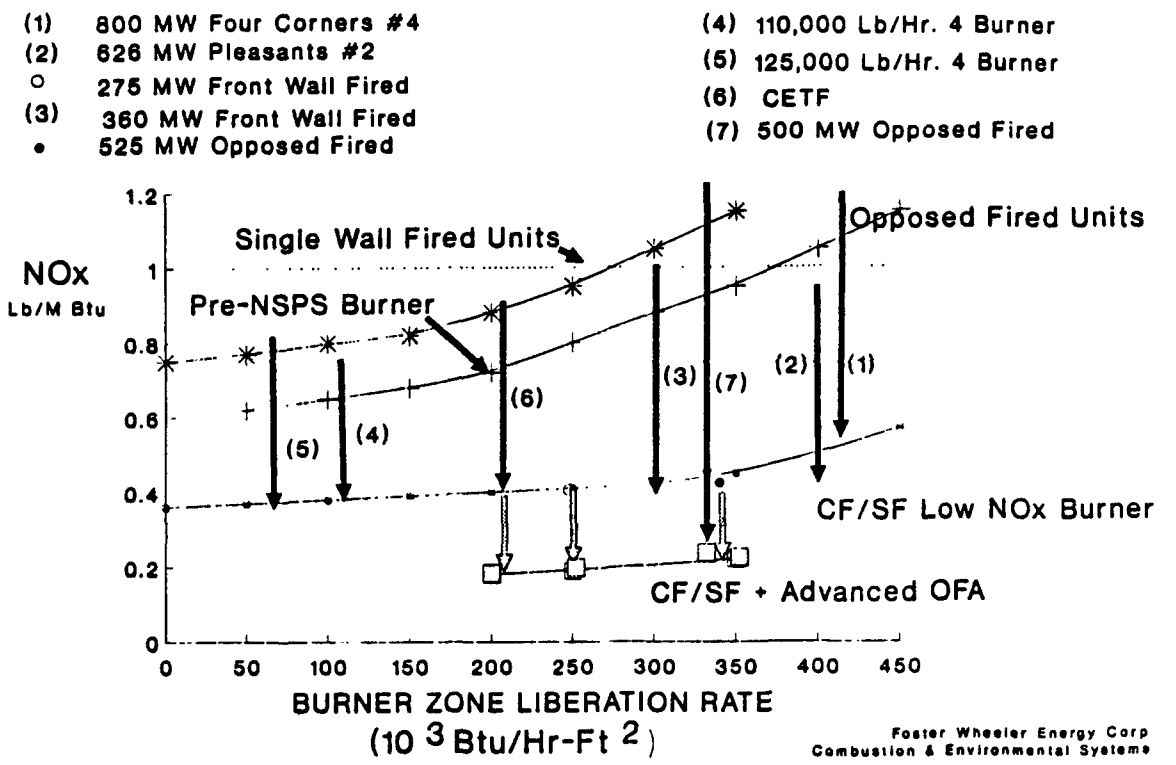


Figure 4-1. NO_x reduction summary of FWEC CF/SF LNB (Vatsky, 1991)

increases in pressure drop can result in costly fan upgrades and higher operating costs. One additional concern with LNB retrofit for wall units is the increased flame length and potential flame impingement on furnace waterwalls causing overheat, excessive slagging and tube failure.

Some increase in UBC content of the flyash can also occur, as discussed in Section 7. The amount of this loss will depend on the coal type (e.g., low volatile eastern bituminous coals will result in higher combustion efficiency losses) and the degree of burner staging. Figure 4-2 illustrates this dependency. The data in this figure were obtained from pilot-scale tests conducted at the B&W combustion research furnace, but is indicative of full-scale UBC trends. The data show how NO_x is reduced by lowering the stoichiometry at the burner. A burner stoichiometry of 1.10 indicates 10 percent excess air. The Utah subbituminous coal, which has the highest volatile content of the three coals used, has the lowest emissions. Figure 4-2 also shows that when burner stoichiometry is reduced the unburned carbon in the flyash increases. Unburned carbon in the ash is an indicator of combustion inefficiency. In these tests, the unburned carbon increased nearly 4 percentage points by reducing the burner stoichiometry from 1.3 to 1.10. Coals with low volatile matter have higher unburned carbon losses. Increasing the fineness of the pulverized coal can often offset this efficiency loss. Section 7 provides additional discussion on the potential effect of LNB retrofit on UBC levels in flyash and other combustible emissions.

Overall, the performance of LNB retrofits on existing wall- and opposed-fired boilers has shown a range in NO_x reduction from about 35 to 55 percent with controlled NO_x levels in the range of 0.40 to 0.64 lb/MMBtu including both short- and long-term test results on all coals and excluding retrofits on post-NSPS or new units. Long-term test results on domestic pre-NSPS units burning low volatile bituminous coal are limited to Hammond Unit 4 and Colbert Unit 3 showing a range in controlled NO_x from 0.47 to 0.64 lb/MMBtu. Several retrofit difficulties have been experienced at GPC's Hammond Plant, including burner fires due to plugging and reduced air cooling. NO_x reduction performance was in part limited by low pulverizer fineness (about

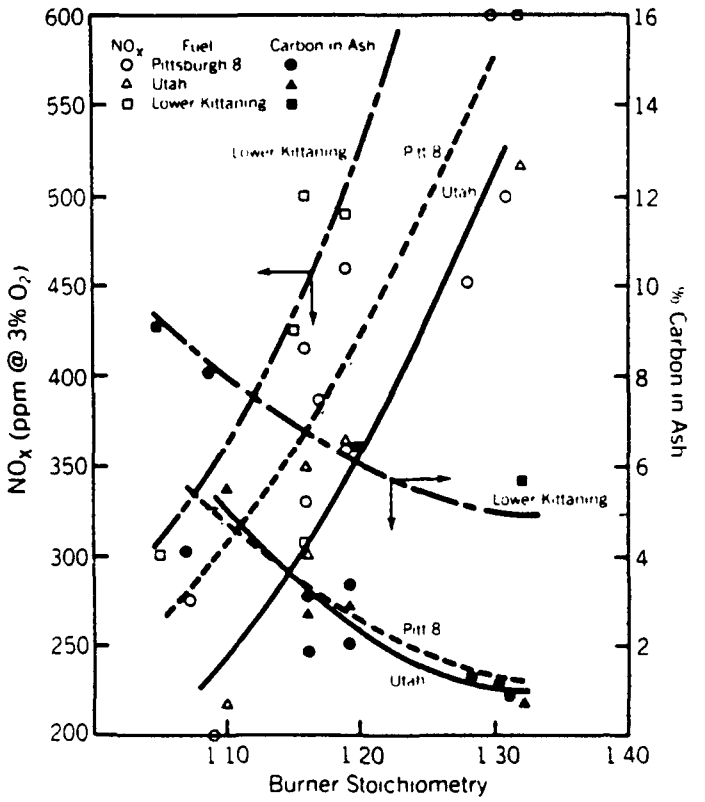


Figure 4-2. Fuel effects: XCL burner plus modified impeller (LaRue, 1989)

64 percent through 200 mesh) pointing to the need for auxiliary equipment upgrade with some LNB retrofits.

4.1.3 Low-NO_x Burners with Overfire Air (LNB + OFA)

This section deals with the use of separate OFA in conjunction with LNB to achieve greater NO_x reduction efficiencies. The use of OFA with LNB dates back to the early 1970s, when it was used by B&W and CE to comply with the early NO_x NSPS levels (LaRue, 1990). The OFA proved to be effective but for the most part unnecessary to achieve regulated limits because of adequate LNB NO_x reduction efficiencies on new Subpart D and Subpart Da boilers. Therefore, the use of OFA ports was discontinued primarily for wall-fired boilers. Tangential units generally continued the use of close-coupled OFA. More recently, as newer regulations set lower NO_x limits, the use of separate OFA ports with LNB is being reevaluated to augment the NO_x reduction efficiency in some retrofit applications.

4.1.3.1 LNB + SOFA for Tangential Boilers

Table 4-4 lists LNB + SOFA applications for tangential-fired boilers. In the United States, there are ongoing demonstrations of LNCFS II and LNCFS III burners for tangential boilers. These recent burner designs by ABB-CE incorporate SOFA above the main burner zone to permit additional combustion staging. The design configurations of LNCFS II and LNCFS III, along with other LNB designs, can be found in Appendix C. Domestic applications of these burner systems have shown NO_x reductions in the range of about 30 to 50 percent, depending on boiler load, fuel type, and degree of staging. Corresponding NO_x levels for tangential boilers ranged from 0.28 to 0.45 lb/MMBtu.

Table 4-4. Partial list and performance of coal-fired LNB+SOFA applications on tangential boilers

Burner Type	Manufacturer	Retrofit Applications	Coal Type	Reported Performance	References
LNCFS II	ABB-CE	U.S. Applications:			
		• PSC Valmont 160 MWe Unit 5 (Pre-NSPS)	W. Bituminous	Short-term tests showed 56% reduction at full load to 0.29 lb/MMBtu and 50% reduction at 75% load to 0.33 lb/MMBtu using 27% OFA w/efficiency loss.	Hunt, 1991
		• PSC Cherokee 350 MWe Unit 4 (Pre-NSPS)	W. Bituminous	Short-term 48% reduction at full load to 0.28 lb/MMBtu; 38% reduction to 0.32 long-term with minor efficiency loss. SOFA most responsible for reduction.	Hunt, 1992
		• GPC Lansing Smith 200 MWe Unit 2 (Pre-NSPS)	E. Subbitumin.	30-day mean reported at 34% reduction to 0.45 lb/MMBtu. Required higher O_2 with slight LOI improvement.	Hardman, 1992
LNCFS III	ABB-CE	U.S. Applications:			
		• GPC Lansing Smith 200 MWe Unit 2 (Pre-NSPS)	E. Bituminous	30-day mean reported at 35% reduction to 0.44 lb/MMBtu. Required increase in O_2 with 1-2% LOI increase.	Hunt, 1992
		• UE Labadie 600 MWe (pre-NSPS)	MW. Bituminous	30-50% NO_x reduction from baseline level of 0.5 to 0.69 lb/MMBtu over load range. Short-term tests.	Smith, 1992
PM	MHI	U.S. Application:			
		• KP&L Lawrence 400 MWe Unit 5 (Pre-NSPS)	MW. Bituminous FR=1.13	Short-term 39% reduction at full load to 0.27 lb/MMBtu and 27% reduction at 50% load to 0.32 lb/MMBtu.	Lewis, 1989
CCTFS	ABB-CE	Foreign Application:			
		• ENEL Fusina 160 MWe Unit 2	Several coals FR=1.67 to 2.35	Short-term tests at full load show reductions of 50 to 63% to 0.25 to 0.34 lb/MMBtu. Required 84% stoichiometry with LOI increase.	Ghiribelli, 1992
SGR	MHI	Foreign Application:			
		• EPDC Matsushima 500 MWe Units 1&2	Several coals	30-50% NO_x reduction to 0.27-0.40 lb/MMBtu depending on volatility of coal.	Tokuda, 1987

LNCFS, PM, CCFTS, and SGR are LNB+SOFA systems for tangential boilers
CF/SF and HTNR are LNB for wall-fired boilers, here retrofitted with separate OFA or AOFA

ABB-CE: Asea Brown Boveri-Combustion Engineering
CCTFS: Concentric Clustered Tangential Firing System
ENEL: Ente Nationale Energia Electrica
EPDC: Electric Power Development Company
GPC: Gulf Power Company
KP&L: Kansas Power & Light
LNCFS: Low NO_x Concentric Firing System
MHI: Mitsubishi Heavy Industry
PM: Pollution Minimum
SGR: Separate Gas Recirculation

Additional LNB + SOFA configurations for tangential boilers include burners that have found application primarily in Japan and Italy. Two LNBs developed by MHI, the SGR and the PM, also incorporate FGR to provide a more distinct separation between the fuel rich and fuel lean zones of the burner. This separation is intended to enhance the degree of NO_x control. However, in the United States, FGR has not been used in connection with these controls. The only demonstration of this Japanese LNB + OFA technology in the United States is the PM burner retrofit at KP&L Lawrence Station. This retrofit did not use FGR because pilot-scale tests sponsored by EPRI had revealed little additional benefit from the use of FGR (Tokuda, 1987).

The performance of the PM burner is heavily dependent on the amount of OFA as is the case for LNCFS II and LNCFS III burner systems. NO_x reductions to as low as 100 ppm (0.13 lb/MMBtu) have been reported with Japanese high volatile coals (Tokuda, 1987; Nakabayashi, 1983). These extremely low-NO_x levels are not deemed attainable with U.S. high-rank eastern coals that have typically higher fuel ratios (ratio of fixed carbon to volatile matter from the coal proximate analysis), which reduces the effectiveness of combustion staging (Tokuda, 1987).

Generally, NO_x reduction performance for this combination of controls have been reported to reach as high as 55 percent for some tangential units. For tangential units, controlled levels below 0.3 lb/MMBtu have been reported during short-term tests for several of these retrofits at selected loads and operating conditions. The only two long-term (30-day average test period) tests, both on the Lansing Smith Unit 2 boiler with LNCFS II and LNCFS III, have shown more modest performance in the range of 35 percent reduction to about 0.45 lb/MMBtu. The SOFA on these units was identified as responsible for most of the reduction in NO_x from baseline levels. This is not too surprising because the distance between the primary burner zone and the SOFA parts provide the longest residence time available between the substoichiometric primary zone and the SOFA level for total fuel nitrogen reduction to N_2. Various tilt and yaw mechanisms on the individual coal and air nozzles at each evaluation allow for combustion optimization for low-NO_x, combustion efficiency, waterwall protection, and steam temperature control.

4.1.3.2 LNB + OFA for Wall-Fired Boilers

For wall- and opposed-fired boilers, the CF/SF burner manufactured by FWEC has been used in United States applications in connection with OFA. In these systems, 10 to 20 percent of the total air is diverted to OFA ports. Table 4-5 lists two retrofits on pre-NSPS units, one burning eastern bituminous coal and another burning western subbituminous coal. All test data available to date are short term and show a controlled NO_x level of approximately 0.35 to 0.55 lb/MMBtu. The controlled levels are as low as 0.33 lb/MMBtu for higher volatile coals, and 0.54 lb/MMBtu for a lower volatile eastern bituminous coal at the GPC Hammond Unit 4 demonstration project. Also, it is important to note that this combination of controls has proven most effective on larger post-NSPS furnaces or boilers originally designed with OFA ports. As discussed in Section 4.1.1, operation of pre-NSPS boilers with OFA causes operational problems and a loss of fuel combustion efficiency. In fact, this combination of controls has generally resulted in a significant increase in LOI especially in the most recent demonstration at the Hammond Plant.

In summary, the data on LNB + OFA technologies are sparse, and limited to the most recent demonstrations at Lansing Smith and the Hammond Plant. Because tests on ongoing, additional results are anticipated to better define the performance range. However, it appears that, on a short-term basis, tangential boilers burning high-volatile coals may be able to achieve NO_x levels as low as 0.30 lb/MMBtu, whereas on a long-term compliance basis with eastern bituminous coals, levels of 0.45 lb/MMBtu seem more appropriate. For wall-fired boilers, NO_x reduction projections for the NESCAUM population of pre NSPS units are more tenuous. The limited data suggest

Table 4-5. Partial list and performance of coal-fired LNB+OFA applications on wall-fired boilers

Burner Type	Manufacturer	Retrofit Applications	Coal Type	Reported Performance	References
CF/SF+OFA	FWEC	U.S. Applications:			
		• GPC Hammond 500 MWe Unit 4 (Pre-NSPS)	E. Bituminous	Short-term 60% reduction reported to 0.54 lb/MMBtu at 95% load. Significant increase in LOI reported.	Sorge, 1992
		• PSNM San Juan 360 MWe Unit 1 (Pre-NSPS)	W. Subbitumin.	Reduction from .95 to 0.33 lb/MMBtu with short-term tests. Unit designed with OFA ports.	Vatsky, 1989
		• APC Pleasant 626 MWe Unit 2 (Post-NSPS)	High vol Bitumin. (FR=1.3-1.4)	Reduction of NO_x from 0.7 to 0.33 lb/MMBtu (67%) on short-term tests. Unit designed with OFA ports.	Vatsky, 1989
		Foreign Applications:			
		• TPC Hsin-Ta 500 MWe Unit 1 (Post-NSPS)	Various low to high vol. FR=1.15 to 2.28	Reported long-term 62% reduction to 0.266 lb/MMBtu with no effect of fuel type	Vatsky, 1991
HTNR+OFA	BHK	Foreign Applications:			
		• EPZ Maas 166 MWe Unit 5	MedVol FR=1.49	Long-term 64% reduction to 0.33 lb/MMBtu. Little additional information.	VanDer Kooji, 1991

LNCFS, PM, CCFTS, and SGR are LNB+SOFA systems for tangential boilers
CF/SF and HTNR are LNB for wall-fired boilers, here retrofitted with separate OFA or AOFA

APC: Allegheny Power Company
BHK: Babcock Hitachi K K.
CF/SF: Controlled Flow/Split Flame
FWEC: Foster Wheeler Energy Corporation
HTNR: Hitachi NO_x Reduction
PSNM: Public Service of New Mexico
TPC: Taiwan Power Company

controlled NO_x levels as low as 0.35 for high volatile coals and 0.55 for lower volatile coals. Although, higher NO_x levels are projected for the Hammond Plant where long-term test data are generated, optimization of pulverizer performance and other burner settings may provide solutions to early operational problems and additional reduction from the current NO_x levels. Boiler efficiency losses for the LNB+OFA combination, at times excessively high, should be anticipated as increases in both LOI and excess air levels have been reported. NO_x levels as low as 0.25 lb/MMBtu for some foreign installations and for the PM burner at KP&L Lawrence Station are considered unlikely target levels for current LNB+OFA technologies because these levels reflect performances obtained with high volatile levels on a short-term basis and with newer large furnace designs.

4.1.4 Reburning or Fuel Staging

Reburning or fuel staging involves the injection of fuel above the main burner zone to destroy the formed NO by passing the primary zone gases through a flame (reburning) or through a low oxygen reducing zone in which NO can be reduced to N_2 (fuel staging). OFA is then introduced to complete combustion of the fuel-rich products leaving the reburning zone, and in so doing, to bring the overall excess air in the normal range of 15 to 20 percent. This OFA must be introduced sufficiently downstream of the reburning fuel to provide the residence time needed for the NO_x reduction reactions to take place while still completing combustion.

The effect of reburning on NO_x has been known for sometime. In repowering cogeneration plants, for example, NO_x emitted from the prime mover (e.g., a gas turbine) passes through a fuel-fired boiler and is partially destroyed such that the combination of the turbine and boilers NO_x emissions is less than if the units were fired separately. In the fuel staging approach, the staged fuel is used to create a localized reducing zone where the NO_x is reduced prior to the addition of air to fully combust the added fuel.

Much of the developmental and implementation work for fuel staging techniques has taken place in Japan. Mitsubishi Heavy Industries (MHI) has developed the Mitsubishi Advanced Combustion Technology (MACT) process, which is reported to attain 50-percent NO_x reduction (Araoka, 1987 and Murakami, 1986). The technology has been used in Japan on at least one large 600 MWe PC boiler and several oil/gas-fired units in connection with LNB operation (Murakami, 1986). B&W, under license with BHK, is offering the In-Furnace NO_x Reduction (IFNR) process. In the U.S., with the exception of the ongoing demonstrations identified below, the technologies of reburning and fuel staging have not been commercially introduced for either new or retrofit units (EER, 1991). However, this NO_x reduction approach offers one of the few potential control methods for cyclone and wet-bottom (slagging) wall-fired boilers.

Demonstrations are underway to evaluate the retrofit potential and control performance of fuel staging on five utility boilers, three cyclone units, one tangential boiler, and one wall-fired boiler:

- Illinois Power, Hennepin Station 71 MWe Unit 1 tangential boiler (Borio, 1991)
- City Water, Light and Power, Lakeside Station 33 MWe Unit 7 cyclone boiler (DOE, 1991; EER, 1991)
- Ohio Edison, Niles 108 MWe Unit 1 cyclone boilers (Brown, 1992)

- Public Service of Colorado, Cherokee Station 158 MWe Unit 3 wall-fired boiler (EER, 1991)

- Wisconsin Power and Light, Nelson Dewey Station 100 MWe Unit 2 cyclone boiler (Yagiela, 1991)

The first four demonstrations use natural gas for the reburning fuel (NGR), and the last uses pulverized coal. The reburn technology used in the first two demonstrations is combined with dry sorbent injection (SI) for simultaneous NO_x/SO_x control. The demonstration of NGR at Cherokee Unit 3 is not currently underway and will eventually be installed in combination with LNB for a NO_x reduction target of 70 percent.

Because of its clean burning properties, natural gas holds better promise for a more efficient reburning fuel for all boiler types. NGR is also relatively straightforward to retrofit and it has the benefit of reduced SO_2 emissions because of displaced coal. One full-scale demonstration of NGR on a tangential boiler has shown NO_x reductions from 400 ppm to a range of 120 to 150 ppm with a reburn zone stoichiometry of 0.9 (Bartok, et al., 1991). More recent results reported by May and Kruger indicate a constant long-term performance of 60 percent reduction to 0.28 lb/MMBtu (200 ppm) with 18 percent natural gas and a reburn stoichiometry of 0.90. FGR is often used in connection with NGR to enhance penetration and mixing of the natural gas in the furnace. The performance of NGR on one cyclone boiler (Niles Unit 1) has shown NO_x reductions in the range of 46 to 48 percent over the long term to levels on the order of 0.4 lb/MMBtu (300 ppm), with acceptable CO levels, and an overall efficiency loss of about 0.6 percent due principally to increased flue gas moisture (Brown, 1992). The principal disadvantages of natural gas as the reburning fuel are that it carries a significant fuel differential penalty, and it may not be economically feasible to ensure an adequate and constant supply of this premium fuel.

Pulverized coal as a reburning fuel has been evaluated at the Nelson Dewey Station with considerable success. A schematic of this retrofit, shown in Appendix C, illustrates the hardware requirements, including the use of a high-efficiency pulverizer. Preliminary results show NO_x reductions of 30 to 53 percent over the load range of the boiler, with improved boiler thermal performance because of reduced furnace slapping (Newell, 1992). Contrary to NGR, reburning with pulverized coal is considered limited in its application to cyclone units because these furnace designs provide better residence times for pulverized coal to complete its combustion then would otherwise be possible in wall and tangential boilers.

In summary, these initial tests have shown that reburning has the potential to be an effective control technology. However, long-term testing remains to adequately address control performance, operational impacts, and commercial feasibility.

4.1.5 Retrofit Potential for the NESCAUM Boilers

Table 4-6 presents estimates of the potential NO_x reduction from coal-fired utility boilers in the NESCAUM region. For this analysis, only the most common PC-fired boilers were included. Other coal-fired designs, such as stokers and vertical or down-fired units, account for a minor fraction of the overall coal-fired capacity, as discussed in Section 2. The estimates for systemwide NO_x reduction potential, shown on the far right of the table, were calculated as follows:

Table 4-6. Estimates of retrofit NO_x reduction potential for pre-NSPS coal-fired boilers in the NESCAUM region

Control Type	Applicable Boiler Type	Percent of Total Coal-Fired Capacity	Estimate of Retrofit Applicability (%)	Total Applicable Capacity (MWe)	Applicable Baseline NO_x Emissions (Tons/yr)	Estimated NO_x Reductions Potential (Tons/yr)
OFA[a]	Tangential	35	60	1,800	30,000	4,500-9,000
	Wall	14	50	500	13,000	2,000-3,300
	Opposed	27	50	700	21,000	3,200-5,300
LNB[b]	Tangential	35	80	2,500	40,000	10,000-12,000
	Wall	14	80	1,700	20,000	7,000-11,000
	Opposed	27	80	1,600	34,000	12,000-19,000
Reburning[c]	Tangential	35	70	2,000	35,000	16,000-23,000
	Wall	14	70	700	18,000	8,100-12,000
	Opposed	27	70	1,000	29,000	13,000-20,000
	Cyclone	10	80	600	22,000	9,900-14,000
	Tangential and wall wet-bottom	10	50	600	20,000	9,000-13,000
LNB + OFA[a]	Tangential	35	60	1,800	30,000	9,000-15,000
	Wall	14	50	500	13,000	5,200-7,800
	Opposed	27	50	700	21,000	8,400-13,000

[a]SOFA for tangential units. The use of OFA can result in operational problems that can limit its NO_x reduction capability, application, and overall feasibility of operation. Estimates of retrofit applicability are lower to reflect the early status of technical demonstration (especially for wall-fired boilers) and operational problems experienced to date.

[b]All LNB designs for tangential boilers come equipped with CCOFA. Estimates of retrofit applicability are high to reflect the commercial availability of LNB designs and the larger experience base compared with other controls.

[c]Reburning with pulverized coal is targeted primarily for cyclone units. NGR is being evaluated for dry- and wet-bottom designs. Assigned retrofit applicability assumes that the technology has been fully demonstrated and is offered commercially.

$$\begin{bmatrix} Baseline \\ NO_x \end{bmatrix} x \begin{bmatrix} Estimate\ of\ Control \\ Applicability \end{bmatrix} x \begin{bmatrix} Range\ in\ Percent\ NO_x \\ Reduction\ Efficiency \end{bmatrix} \quad (4\text{-}1)$$

For example, current baseline levels for dry-bottom tangential coal-fired boilers are about 50,000 tons/yr (see Figure 2-1). For SOFA control, the retrofit applicability is estimated at 60 percent, and the NO_x reduction efficiency was given in the range of 15 to 30 percent with controlled NO_x levels in the range of 0.40 to 0.50 lb/MMBtu. Thus, the calculated NO_x reductions are as follows:

$$(50{,}000\ tons/yr)\ x\ (0.6)\ x\ (0.15\ to\ 0.30) = 4{,}500\ to\ 9{,}000\ tons/yr \quad (4\text{-}2)$$

where 15 to 30 percent is the estimated NO_x reduction efficiency for the technology (see Table 4-1), calculated from current average baseline emission factors for tangential boilers (see Table 3-3) and controlled NO_x levels reported in the literature.

The calculation of systemwide NO_x reduction potential includes the estimate for applicability of the retrofit technology to the existing boiler population. Although all boilers can theoretically be retrofitted with some combination of these controls (e.g., most dry-bottom units can be retrofitted with LNB, whereas far fewer wall fired boilers can utilize OFA without adverse operational impact), site-specific constraints can make the retrofit of some technologies impractical or much less attractive than others. For example, OFA may not prove a viable option for some boilers because of space constraints due to structural interferences and furnace access; small furnace volume, resulting in severe limitations to the amount of OFA introduced, and, thus, NO_x reduction; and poor steam temperature control, resulting in significant energy penalties. Tangential boilers built after the 1971 NSPS, and especially those built after the 1978 NSPS, were generally equipped with OFA. Because all the PC-fired boilers in that age group were introduced in the last 10 years, it is very likely that these units already have OFA. Therefore, the retrofit of OFA cannot be credited for this boiler design in this age group.

In the case of gas reburning, access to natural gas, and long-term gas supply contracts, will dictate the viability of this control option for all coal-fired boilers, including cyclone units.

The retrofit of LNB with or without OFA can be quite expensive in cases where access to indoor boilers is impossible without significant demolition and reconstruction, coupled with the replacement of a substantial portion of the coal pipes, furnace, windbox, ducting, fans, and control system. In addition, retrofits of older facilities can become more complicated when asbestos removal is necessary.

Estimates by EPRI put the percentage of the retrofit capacity for low-NO_x burners at about 50 to 80 percent, depending on firing configuration and boiler manufacturer (Miller, 1985). It is clear that a significant portion of the most recent boiler population of tangential-, wall-, and opposed-fired units can be retrofitted with today's low-NO_x burners. LNB technology represents the retrofit NO_x control method most accepted by the utilities, especially if it can be accomplished with minor modifications to the furnace, windbox, and auxiliary equipment. This is often not the case for older units because the existing windbox and auxiliary equipment may require upgrade or replacement to ensure adequate operation and performance. Typically, smaller and older units may be less capable of utilizing this and other low-NO_x technologies without significant equipment upgrade.

Therefore, we selected a retrofit applicability factor of less than 100 percent for each retrofit control technology to estimate the systemwide NO_x reduction potential. The applicability factor was estimated to vary between 50 and 80 percent for all control technologies, as in the EPRI estimate.

This information, together with the estimated baseline and controlled emission levels for each control application, resulted in estimates of the total NO_x reduction potential, shown in the far right column of the table. For example, OFA retrofitted to about 3,000 MWe of applicable tangential-, wall-, and opposed-fired boiler capacity is estimated to achieve 10,000 to 17,000 tons/yr of NO_x reduction. LNB retrofit for dry-bottom units is estimated to contribute the highest NO_x reduction with a target coal-fired retrofit capacity of about 5,800 MWe and NO_x reductions reaching 42,000 tons/yr. The range in NO_x reduction potential calculated for each boiler design/NO_x control combination is due to variations in the NO_x reduction efficiencies estimated for each control technology as shown in Table 4-1 and in Appendix D.

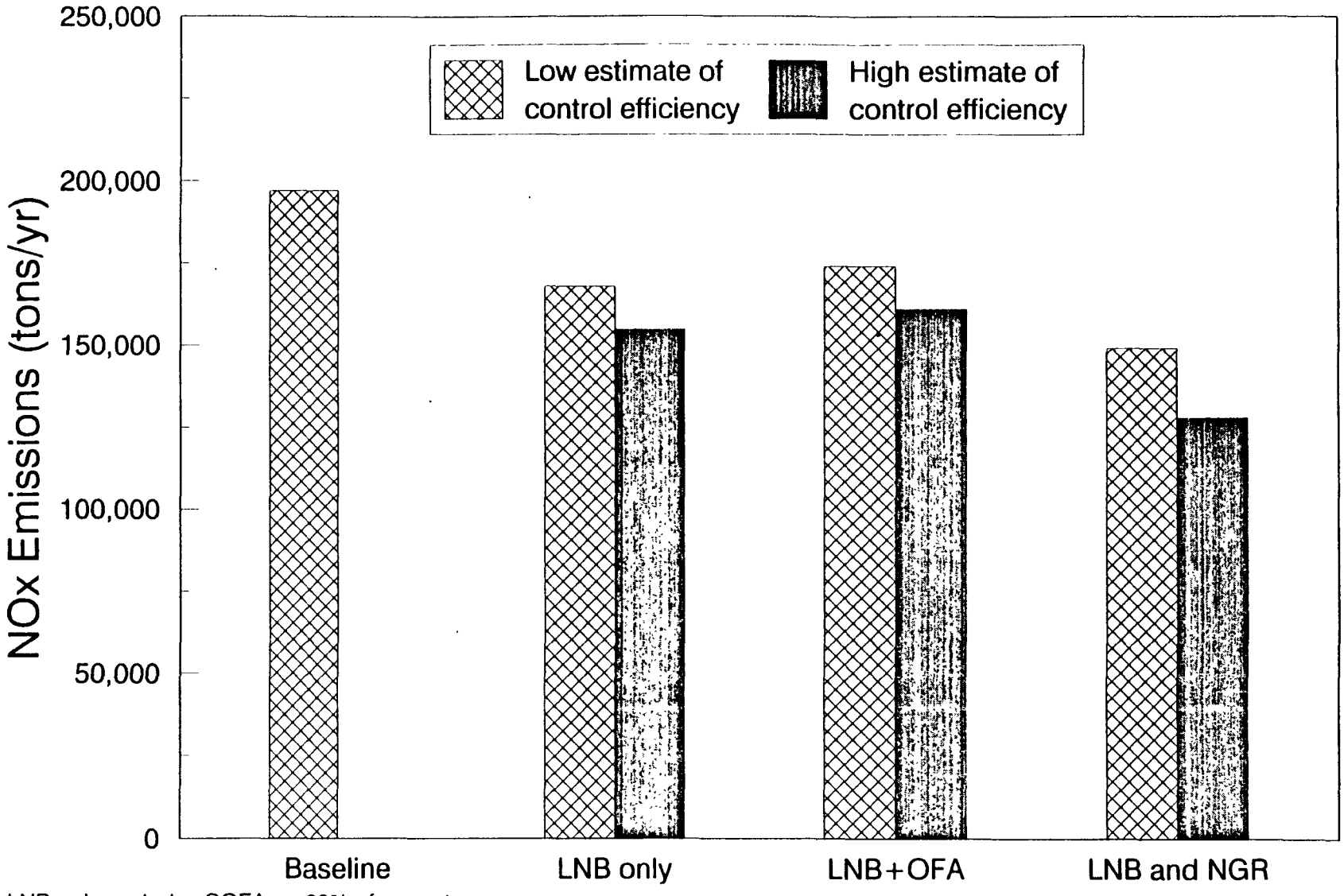
Figure 4-3 illustrates the NO_x reduction potential for coal-fired boilers based on three combustion control retrofit scenarios. The first scenario is based on the retrofit of 80 percent of the current dry-bottom, PC-fired tangential-, wall-, and opposed-firing capacity with LNB. The second scenario assumes retrofit capability of 50 to 60 percent for LNB+OFA on these same units. The third scenario adds the retrofit of 80 percent of cyclone capacity with 50-percent retrofit of wet-bottom boilers with reburn technology. The baseline NO_x emissions from all coal-fired boilers are about 200,000 tons/yr in the NESCAUM region. This level can be reduced to approximately 155,000 to 168,000 tons/yr using LNB-based combustion modification controls. For comparison, NO_x emissions reductions achieved with LNB+OFA are slightly lower than those achieved with LNB only, because of the reduced estimate of retrofit capability assigned to OFA. With the added control of wet-bottom and cyclone units with reburn technology, systemwide NO_x emissions from coal-fired boilers are estimated to be controlled to a range of 127,000 to 147,000 tons/yr from current baseline levels of about 200,000 tons/yr.

The estimates of NO_x reductions from these units are offered only as guidelines to illustrate the capability of existing control technologies on a NESCAUM region-wide basis. The results are heavily influenced by the assumption used for the applicability of NO_x controls to the existing population of boilers in the NESCAUM region. More definitive control levels require detailed site-by-site specific analyses of the retrofit potential, actual baseline emissions, and current and future fuel use practice and capacity factors.

4.2 COMBUSTION CONTROLS FOR OIL- AND GAS-FIRED BOILERS

The modification of combustion in full-scale, gas-, and oil-fired utility boilers can result in significant NO_x reductions, at times reaching 90 percent from uncontrolled levels. Combustion modification controls for these boilers have been implemented since the early 1970s, primarily in California. Utility boilers operated by SCE, Los Angeles Department of Water and Power (LADWP), San Diego Gas and Electric (SDG&E), and Pacific Gas and Electric (PG&E) have been retrofitted with a variety of single and combined techniques to produce controlled NO_x levels in the range of 42 to 255 ppm at 3 percent O_2 (0.053 to 0.323 lb/MMBtu). The low range of emission is normally associated with natural gas firing. The 42 ppm level was achieved from SCE Scattergood Unit 3 which had an initial NO_x level in excess of 1,000 ppm when introduced in the mid-1960s and was retrofitted with a combination of FGR, and derate (Pepper, 1987).

Following a period of low retrofit activity, new efforts are again underway in California to optimize existing combustion controls and introduce new technologies. These efforts are in response to the recent passage of the South Coast Air Quality Management District (SCAQMD)



LNB only excludes SOFA on 80% of current capacity; LNB+SOFA retrofit on 50-60% of capacity; NGR on 50-60% of wet-bottom capacity

Figure 4-3. Estimates of combustion-controlled NO_x emission levels for coal-fired boilers in the NESCAUM region

Rule 1135, which will ultimately require controlled NO_x levels as low as 23 ppm (0.03 lb/MMBtu, 0.25 lb/MW-hr) in 1999. Because of these past retrofit efforts there is a wealth of technology and retrofit experience that is directly applicable to the NESCAUM oil- and gas-fired units. Although NO_x reduction successes similar to those of the SCE, LADWP, and PG&E utilities cannot be guaranteed (for example, fuel oil properties, such as fuel nitrogen content, may be different) significant reductions in NO_x are possible.

The control of NO_x from oil and gas fuel combustion relies on the suppression of both fuel and thermal NO with a combination of techniques that stage the combustion and reduce peak temperatures. The applicable TSC techniques are BOOS or biased burner firing and OFA ports. FGR to the windbox is a very effective NO_x reduction technique for these fuels, especially natural gas. FGR becomes less effective when the nitrogen content of the fuel oil is high, e.g., when burning residual oil.

BOOS, FGR, and OFA are by far the most popular retrofit NO_x control techniques for gas- and oil-fired utility boilers. The recent demands for additional NO_x reductions from California utility boilers to levels well below 100 ppm are shifting attention to LNB and postcombustion technologies (Mansour, 1991). New LNBs are being evaluated often not as a replacement for the other controls but as additional combustion modifications needed to stabilize the combustion, minimize furnace vibration, and reduce particulate emissions when higher FGR and OFA rates or additional BOOS are implemented to attain NO_x reductions. In general, there is little experience on the LNB capabilities as stand-alone control methods for oil- and gas-fired boilers. Japanese boilers manufacturers have adopted coal LNB technology to oil and gas burning. Industrial-size-burner manufacturers are also introducing utility oil- and gas-fired LNBs. Another technique that has received some exploratory research, but has no current U.S. application, is the IFNR, or reburning.

Table 4-7 summarizes the performance and hardware modifications for applicable NO_x combustion controls. The table reports percent NO_x reduction efficiencies published in the literature, and estimates of controlled NO_x levels associated with these reductions. The appropriateness of these NO_x reduction efficiencies to the NESCAUM boiler population depends heavily on fuel characteristics, degree of control, and current uncontrolled NO_x levels. Because several of the gas- and oil-fired boilers in the NYPP are currently equipped with some combustion controls, average baseline emissions are already low, and the percent NO_x reduction shown in Table 4-7 are likely to be inflated for the NESCAUM boiler population as a whole. Consequently, estimates of controlled NO_x levels have been adjusted upward to reflect more reasonable performance targets corresponding to uncontrolled boilers. Because of boiler design constraints and fuel properties, some boiler with currently high baseline levels exceeding 1.0 lb/MMBtu may be unable to achieve some of these NO_x control targets without the retrofit of several controls, fuel switching, and possibly derating. The following subsections discuss the NO_x reduction performance and utilization status of these controls. Appendix D provides details on the reported NO_x reduction performance and controlled limits for oil-/gas-fired boilers.

4.2.1 Burners Out of Service (BOOS)

A common low-cost operational modification for gas- and oil-fired boilers with moderate to high NO_x reduction efficiency is biased firing and BOOS. Biased burner firing consists of firing the lower rows of burners more fuel rich than the upper rows of burners. This may be accomplished by maintaining normal air distribution to the burners while adjusting fuel flow so that a greater amount of fuel enters the furnace through the lower rows of burners. Additional air required for complete combustion enters through the upper rows of burners which are air-rich. In

Table 4-7. Combustion controls for oil- and gas-fired utility boilers

Control Technology	Percent NO_x Reduction and Controlled NO_x Levels (lb/MMBtu)[a]		Applicable Boiler Designs	Anticipated Equipment Modifications and System Upgrades
	Pre-NSPS	Post-NSPS		
BOOS or Biased Firing	30 to 35 (0.30 - 0.35) W 15 to 20 (0.20 - 0.25) T	25 to 35 (0.25 - 0.30) W 25 to 40 (0.20 - 0.25) T	Most wall- and T-fired boilers. Several BOOS patterns are possible. Engineering testing needed	Windbox upgrade for effective air management. Fuel control system upgrade. Installation of O_2/CO trim system. Possible modification to superheater and steam attemperation
Windbox FGR	25 to 40 (0.25 - 0.35) W 25 to 40 (0.20 - 0 25) T	20 to 30 (0.25 - 0.30) W 20 to 30 (0.15 - 0.20) T	Most wall- and T-fired boilers. FGR rates most effective up to 15% depending on fuel and O_2.	Installation of FGR fan, ducting, and dampers. Windbox modifications. Removal of asbestos in some older plants. replacement of flame scanners. Installation of O_2 monitoring for windbox. Boiler control and O_2/CO trim.
LNB	40 to 50 (0.25 - 0.30) W 25 to 50 (0.15 - 0.25) T	30 to 40 (0.20 - 0.25) W 20 to 40 (0.15 - 0.20) T	Most wall- and T-fired boilers. Installation may be needed for improved flame stability with other controls	Modification of windbox for compartmentalized combustion air distribution. Burner replacement and possible additional burner parts and waterwall modifications. Installation of O_2/CO trim system. Fuel supply and valving, and burner control system upgrade.
BOOS+FGR	40 to 50 (0.25 - 0.30) W 30 to 50 (0.15 - 0.20) T	40 to 50 (0.15 - 0.20) W 30 to 40 (0.15 - 0.20) T	Most wall- and T-fired boilers. See above for combination of BOOS and FGR	Combination of BOOS and FGR retrofit equipment requirements and upgrades.
BOOS (or OFA) +FGR+LNB	60 to 80 (0.10 - 0.20) W 40 to 70 (0.10 - 0.20) T	45 to 70 (0.10 - 0.20) W 40 to 60 (0.10 - 0.15) T	Most wall- and T-fired boilers with possible exception of high heat release furnaces	Combination of BOOS, FGR, and LNB equipment modifications and upgrades. Possible requirement for fan upgrades and asbestos removal for older plants.
Reburning (NGR)[b]	50 to 60 (0.20 - 0.25) W 50 to 60 (0 15 - 0.20) T 50 to 60 (0.25 - 0.30) C	30 to 50 (0.20 - 0.25) W 30 to 50 (0.15 - 0.20) T	Most attractive retrofits include fuel conversion (coal to oil/gas) units because of larger firebox	Installation of reburning fuel and overfire air ports, Replacement of furnace waterwall sections. Possible modifications to superheater tube bank and attemperation. Upgrading of structural support and compartmentalized windbox. Installation of O_2/CO trim and boiler control system. Possible extension of furnace height.

W = Wall-and opposed-fired boilers; T = Tangential (corner)-fired boiler; C = Cyclone-fired boiler.

[a]Percent reductions are determined from reported controlled NO_x levels (See Appendix D) and average baseline emissions in NESCAUM.

[b]NGR experience for oil- and gas-fired units is minimal abroad and nonexistent in the United States. Estimates of control efficiency are speculative.

the BOOS mode, individual burners, or row of burners, admit air only. This reduces the air flow through the active burners, thereby creating fuel-rich and fuel-lean zones that lead to reduced NO_x emissions. These techniques are often described under the common heading off stoichiometric (O.S.) combustion.

These techniques are equally effective for oil- and gas-fired boilers in controlling both fuel and thermal NO_x. BOOS and biased firing are attractive first level NO_x control retrofit because few, if any, equipment modifications are required. Both techniques were used quite extensively on both wall and tangential boilers in the early stages of utility NO_x controls in Southern California. For example, 24 SCE units are currently controlled with a combination of BOOS, NO_x ports (OFA), and FGR. BOOS has also been used quite extensively in the Consolidated Edison system where many gas- and oil-fired boilers produce both electricity and steam. Con Edison has estimated an overall reduction potential due to O.S. of 30 percent to controlled NO_x emissions in the range of 0.20 to 0.35 lb/MMBtu based on direct retrofit experience with BOOS and NO_x ports (Mormille, 1991). Other NO_x reduction estimates have been in the range of 35 to 45 percent (Hunter, 1989) and 35 to 55 percent (Lim, 1980).

The actual percent reduction that can be realized depends on the initial NO_x levels, i.e., the higher the uncontrolled NO_x the higher is the potential for large reductions due to O.S. combustion. The current NO_x levels from pre-NSPS tangential- and wall-fired boilers average 0.24 and 0.52 lb/MMBtu. Estimates of controlled levels in the range of 0.25 to 0.35 would translate to reductions of 0 to 33 percent. In reality, individual boilers will exhibit significantly higher or lower NO_x reductions based on current baseline conditions.

Although large NO_x reductions can be achieved with BOOS, the operational performance of the boiler is generally somewhat degraded because of the need to increase excess air to keep CO, hydrocarbons, and smoke emissions in check. Some limitations in the degree of staging may also result from difficulty in steam temperature control and restrictions on load following capability. Because flame stability problems can also result, care must be taken in selecting the appropriate BOOS and on the degree of staging at each of the remaining burners in service.

4.2.2 Flue Gas Recirculation (FGR)

FGR for NO_x control consists of extracting a portion of the flue gas from the economizer or air heater outlet and returning it to the furnace, admitting the flue gas through the burner windbox. FGR lowers the bulk furnace gas temperature and reduces the concentration of oxygen in the combustion zone. FGR is also referred to as windbox FGR (WFGR) to distinguish it from FGR through the hopper or above the windbox, which is used primarily to control of superheater steam temperature at variable boiler load.

In California, WFGR has been used effectively on utility oil- and gas-fired boilers to achieve significant reductions in NO_x on the order of 40 to 65 percent (Lim, 1980). The amount of reduction varies with the amount of gas recirculated (i.e., degree of control). Figure 4-4 illustrates the effectiveness of WFGR based on the California experience. This experience is based primarily on "clean" fuels (natural gas and low nitrogen distillates), which are more conducive to high NO_x reduction performance compared with heavier grade oils. This is important when applying these results to the NESCAUM boilers. Highest NO_x reductions are achieved on natural gas fuel. The low range of NO_x reduction efficiency is associated with oil combustion. WFGR is generally much more effective in reducing NO_x when natural gas is being burned. The range in NO_x reduction depends also on the percent WFGR (typically 20 percent of the total flue gas or less) and the initial NO_x levels. In New York State, the Niagara Mohawk Oswego Unit 6 and Orange and Rockland

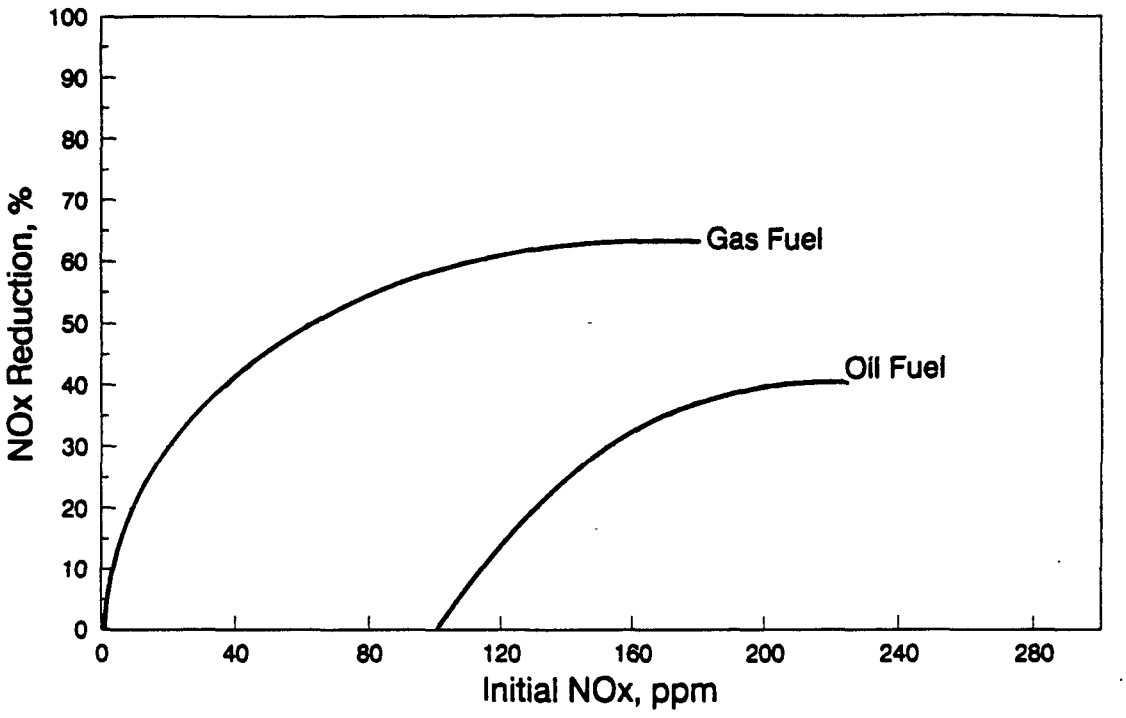


Figure 4-4. NO_x control effectiveness of 20 percent WFGR versus initial NO_x level for gas and oil fuels (Mormile, 1991)

Utilities, Inc., Bowline Unit 2 are already equipped with FGR. Baseline levels of 0.21 and 0.27 lb/MMBtu reported for these units (see Appendix B) are based on the use of WFGR.

Sometimes, the technique is used in connection with many low-NO_x burner designs to achieve very high NO_x reductions on the order 60 to 70 percent. For example, the MHI PM burner uses FGR to achieve a separation between the fuel jets and the secondary air, ensuring sufficient time for NO_x reduction during staging. When using OFA, WFGR can be used to control the superheater steam temperature caused by the lowering of the peak combustion temperature in the furnace.

4.2.3 Overfire Air (OFA)

OFA is generally not a preferred retrofit control for oil- and gas-fired boilers because BOOS can offer similar NO_x reduction efficiency at a fraction of the cost. Also, high heat release furnaces, built from the late 1950s to the first NSPS, are generally not suitable for retrofit of OFA ports because the furnaces are small and there is insufficient volume above the top burner zone to complete combustion. With some units it becomes necessary to derate and modify the superheater tube bank to minimize changes in the heat absorption profile of the unit.

The experience with OFA ports on oil-/gas-fired units can be considered limited. However, some units in California have been retrofitted with OFA ports. NO_x reduction efficiencies for California utilities have been reported to average 24 percent for oil and nearly 60 percent for gas (Lim, 1980). Generally, OFA is used in conjunction with other controls such as WFGR and BOOS.

Potential NO_x reductions are similar to those achieved with BOOS. Operational performance losses similar to BOOS are also encountered (Lim, 1980).

4.2.4 Low-NO_x Burners (LNB)

There are few LNBs for gas- and oil-fired units, and there is little experience with those that are considered commercially available. Because many of the O.S. combustion techniques, such as BOOS and WFGR, have been exploited to the maximum extent possible by utilities subject to stringent NO_x standards, there is renewed interest in the demonstration of oil- and gas-fired LNB technologies. The concept of LNB is appealing because it can avoid some of the operational performance losses associated with BOOS and OFA. As mentioned before, LNB is currently used primarily in conjunction with other controls. There is little documentation on the NO_x reduction potential for this technology by itself.

Table 4-8 contains a partial list of oil- and gas-fired LNBs that are commercially offered and some known applications and demonstrations. Note that several of these applications combine LNB with other controls such as OFA and FGR. NO_x reductions obtained at Fusina in Italy should be considered with caution because this boiler in primarily a coal-fired unit with multiple fuel firing capability. Consequently, NO_x reductions obtained on this unit cannot be considered as widely applicable to oil-/gas-dedicated units, which are, by design, more compact and have a different heat release profile. Recent results of a low-NO_x burner system retrofitted on New England Power (NEP) Salem Harbor, 435 MWe Unit 4, showed NO_x reduction from 0.6 to 0.34 lb/MMBtu during short-term tests with oil firing (Afonso, 1992). Tests with one row of BOOS prior to LNB retrofit also showed similar NO_x reduction performance. Other burner manufacturers also have LNB technology, but limited information is available on these other designs. Overall, LNB has been applied sparingly on gas- and oil-fired U.S. boilers; estimates for NO_x control performance for LNB alone range from 20 to 50 percent based on the recent NEP retrofit experience.

4.2.5 Combined FGR, OFA and LNB

The largest NO_x reductions can be obtained with a combination of retrofit technologies and operational modifications. The combination of WFGR, O.S., (with OFA ports or BOOS), and LNB provides significant reductions from uncontrolled levels. The current experience for these retrofit combinations is limited to the California utilities where NO_x levels were reduced to the current limits of 42 to 225 ppm (about 0.05 to 0.3 lb/MMBtu) from uncontrolled levels of as high as 900 ppm (McDannel, 1991 and Bayard DeVolo, 1991). It should be recognized, however, that the low end of these emissions were obtained with natural gas. Similar performance with other fuels cannot be expected. Other tests with a combination of FGR and OFA at reduced boiler load have shown NO_x reductions in the range of 60 to 85 percent (Lim, 1980). It should also be recognized that these high NO_x reduction efficiencies are only likely on boilers with initially very high baseline emissions (greater than 1.0 lb/MMBtu).

NO_x reduction performance and controlled limits are supported by retrofit results on several utility boilers in Southern California. NO_x levels as low as 0.06 lb/MMBtu based on short-term (0.10 lb/MMBtu for long-term) were reported for gas firing (Bayard DeVolo, 1991) to 0.20 lb/MMBtu, for several retrofits in the SCE, LADWP, SDG&E systems (Bisonett, 1991; Bayard DeVolo, 1991), and at the Kahe Station of Hawaiian Electric Co. (Kerho, 1991). These NO_x control levels can often be matched by the performance of TSC (OFA or BOOS) with FGR without LNB retrofits.

Table 4-8. Partial list of gas- and oil-fired low-NO_x burner applications

Burner Type	Manufacturer	Retrofit Applications	Reported Performance	References
STS[a]	Riley/Deutsche Babcock	Wall-Fired Boilers: Arzberg Power Station 220 MWe Unit 6 in Germany Vartan Power Station 250 MWe in Sweden More than 520 MWe retrofitted in Europe	0.06 lb/MMBtu for gas 0.2 lb/MMBtu for heavy oil	Lisauskas, 1991
ASR[e]	Riley/Deutsche Babcock	Germany: Several boilers U.S.: Industrial units	50% NO_x reduction with natural gas to about 0.13 lb/MMBtu. Heavy fuel oil to about 0.22 lb/MMBtu.	Oppenberg, 1986
LNCFS	ABB-CE	Corner-Fired Boilers: ENEL Fusina 160 MWe Unit 2 in Italy (primarily a coal-fired boiler)	50-60% NO_x reduction with OFA. Controlled levels reported were 0.14 lb/MMBtu for oil and 0.06 lb/MMBtu for gas.	Tarli, 1991
PG-DRB[b]	B&W and BHK	Hawaiian Electric Co. Kahe 146 MWe. Evaluated for retrofit on LADWP boilers	NO_x reduced to below 0.23 lb/MMBtu with OFA and FGR	Bisonett, 1991 Kerho, 1991
ROPM	ABB-CE and MHI	No installation in U.S.; for wall-fired boilers	25-50 percent NO_x reduction projected from controlled levels to 0.06 to 0.08 lb/MMBtu for natural gas and 0.12 to 0.17 lb/MMBtu for oil	Pepper, 1987
PM[c]	ABB-CE and MHI	No installation in U.S.; several in Japan for tangential boilers	40-50 percent NO_x reduction. Controlled NO_x levels same as ROPM	Pepper, 1987
Dynaswirl	Todd	SCE Osmond Beach Unit 2 and Alamitos	Up to 93 percent NO_x reduction when combined with BOOS and FGR to 0.03 to 0.04 lb/MMBtu at partial load and 0.04 to 0.08 lb/MMBtu at full load	Bayard DeVolo, 1991
DRB XCL	B&W	Italy: ENEL Brindisi Sud Unit 2 No U.S. known retrofits to date. Recently introduced	NA[d]	LaRue, 1989
RV TTL-50	Rodenhuis and Verloop	Salem Harbor Unit and Brayton Point Unit 4	More than 40% reduction to less than 0.35 lb/MMBtu on oil	Afonso, 1992

[a]STS = Swirl Tertiary Separation.
[b]PG-DRB = Primary Gas-Dual Register Burner.
[c]PM = Pollution Minimum.
[d]NA = Not Available.
[e]ASR = Axial-Staged Reburn.

4.2.6 Reburning

Reburning for NO_x control on oil- and gas-fired boilers has received little evaluation in this country. Although technically feasible, the technology is not considered commercial for oil and gas or likely to achieve that status in the near future. The NGR demonstration at Hennepin Station has included tests with natural gas as the primary fuel instead of pulverized coal. This short test demonstration also showed significant reductions. However, because the boiler is designed to burn coal (its furnace is larger than an equivalent oil-/gas-burning furnace) this demonstration is not directly relevant to the analysis of reburn technology on oil-/gas-fired boilers. No other retrofit experience exists in the United States (Pratapas, 1991). Bisonett and McElroy, 1991, recently evaluated the performance and retrofit potential for the IFNR process along with other combustion and FGT controls for five utility boilers in the PG&E inventory (Bisonett, 1991). In that study, NO_x reduction performance was estimated in the range of 47 to 75 percent with boiler derating. No test data were taken to verify this performance. The derating of the boiler capacity was considered necessary because adequate gas residence time must be available in the furnace to complete combustion of the staged fuel. Major extension of the furnace height is another way to achieve this increase in residence time, but the modification is excessively expensive to consider under normal conditions.

In Italy, reburning with propane and fuel oil as reburning fuels on a 35 MWe unit has been experimented to compare the overall effectiveness to other combustion controls available to oil-fired boilers. NO_x reductions of up to 70 percent were achieved with propane and 60 percent with oil as the reburning fuel (DeMichele, G., et al., 1992). Reburning performance and control of CO emissions were sensitive to reburn residence time. A minimum of 0.45 seconds of residence time was reported as necessary to optimize NO_x reduction with adverse increase in CO emissions. In Japan, the application of the MACT process has been reported to achieve significant NO_x reductions (Araoka, 1987 and Murakami, 1986). Usually MACT is applied with LNB to achieve levels of less than 0.15 lb/MMBtu (Araoka, 1987). Performance data for reburn in gas and oil-fired designed units remains limited. In Japan, reburn on PC-fired boilers is the preferred application for the MACT, however.

4.2.7 Retrofit Potential for the NESCAUM Boilers

Table 4-9 provides estimates of the NO_x reduction potential for the retrofit control technologies applicable to oil- and gas-fired utility boilers. These estimates were developed based on assumptions of retrofit applicability (ranging from 50 to 90 percent) and estimates of control levels achieved from current baseline inventories. For example, 80 percent of the wall-fired boiler capacity responsible for 30,000 tons/yr of NO_x emissions is deemed retrofitable with either BOOS or OFA controls that reduce emissions by staging the combustion (TSC). With this technology, control levels are estimated in the range of 0.25 to 0.45 (25 to 35 percent reduction), depending on initial NO_x level (pre- or post-NSPS), fuel type, and several other site-specific factors. These control levels result in a reduction of 7,500 to 11,000 tons/yr of NO_x throughout NESCAUM from this boiler design category. Because these estimates are based on several assumptions, they are offered as guidelines to estimate NESCAUM-wide reduction potentials. Site-specific analyses are required so that accurate predictions can be developed. Generally, lower retrofit potential estimates were used in the case of LNB, combined control (OFA+LNB+FGR), and reburning retrofits because of the lack of reported experience to date and increased retrofit difficulties. High retrofit potential is estimated for BOOS and FGR (or a combination of these controls), because they are relatively easy to retrofit on most boilers. The degree of TSC accomplished will vary with the flexibility that a particular unit has in managing load with BOOS. The retrofit potential of

Table 4-9. Estimates of retrofit NO_x reduction potential for oil- and gas-fired boilers in the NESCAUM region

Control Type	Applicable Boiler Type	Percent of Total Oil/Gas-Fired Capacity	Estimate of Retrofit Applicability (%)	Total Applicable Capacity (MWe)	Applicable Baseline NO_x Emissions (Tons/yr)	Estimated NO_x Reductions Potential (Tons/yr)
TSC (OFA or BOOS)	Tangential	44	90	11,000	66,000	9,900-26,000
	Wall	31	80	5,800	30,000	7,500-11,000
	Opposed	14	80	2,900	26,000	6,500-9,100
FGR	Tangential	44	80	9,500	59,000	12,000-24,000
	Wall	31	80	5,800	30,000	7,500-12,000
	Opposed	14	80	2,900	26,000	6,500-10,000
LNB	Tangential	44	60	7,200	44,000	11,000-22,000
	Wall	31	60	4,400	23,000	6,900-12,000
	Opposed	14	60	2,200	19,000	5,700-9,500
TSC (BOOS or OFA) + FGR	Tangential	44	80	9,500	59,000	18,000-30,000
	Wall	31	80	5,800	30,000	12,000-15,000
	Opposed	14	80	2,900	26,000	10,000-13,000
OFA + LNB + FGR	Tangential	44	50	6,000	37,000	15,000-26,000
	Wall	31	50	3,600	19,000	8,600-15,000
	Opposed	14	50	1,800	16,000	7,200-13,000
Reburning[a]	Wet-bottom boilers	11	50	1,900	13,000	6,500-7,800

[a]Reburning applied to high heat release rate wet bottom furnaces only, including cyclones. Other controls applicable to dry-bottom furnaces only. NO_x reduction estimates are highly speculative at this stage of technology development.

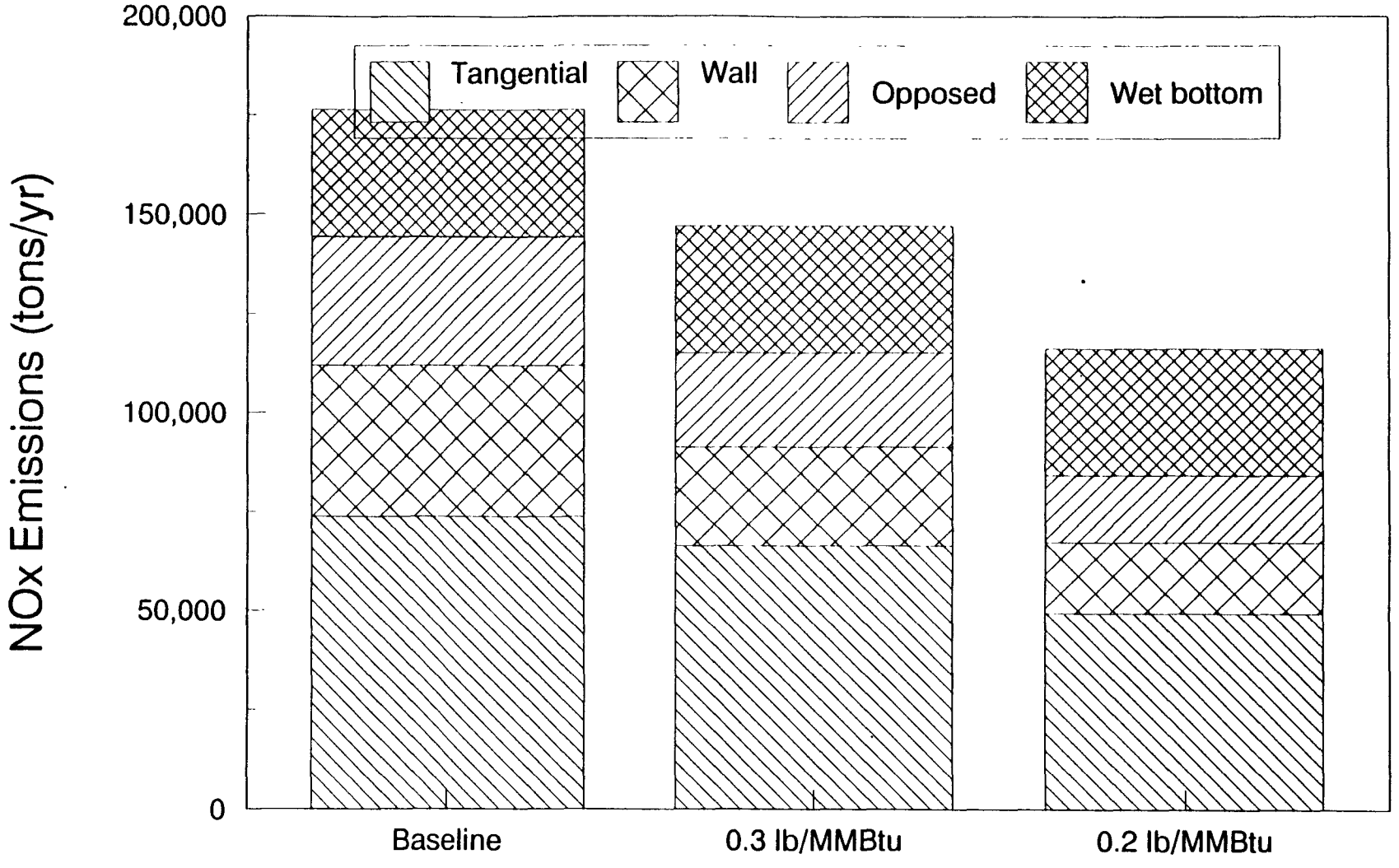
LNB-based controls is considered to be less compared to TSC+FGR because of more limited experience.

The NO_x reduction estimates in Table 4-9 can be somewhat misleading because several boilers are already controlled with combustion modifications. Also, several boilers currently have low NO_x levels, and, because of this, significant NO_x reductions are not anticipated from these units. Therefore, another estimate of NESCAUM-wide NO_x reduction can be obtained by calculating the contribution of each oil-/gas-fired boiler required to meet a certain NO_x level. Figure 4-5 illustrates this estimate, which assumes widespread application of emission control levels of 0.3 or 0.2 lb/MMBtu to all dry-bottom boilers. The figure shows that a control level of 0.3 lb/MMBtu results in little reduction from the current emission inventory attributable to tangential units. This is because most tangential boilers are already reported to emit NO_x at this level. Most of the estimated 30,000 tons/yr of NO_x reduced under this scenario is contributed principally by reductions in NO_x from wall- and opposed-fired boilers. Under the 0.2 lb/MMBtu control NO_x scenario, 50,000 to 60,000 tons/yr are reduced with significant contributions from all major boiler types. As indicated, wet-bottom units with high furnace heat release rates remain uncontrolled because these are significant uncertainties in the applicability and performance of applicable controls due to limited retrofit experience. Combustion controls with reburning on these units are likely to add no more than 10,000 tons/yr to the overall reduction in the NESCAUM region.

4.3 FLUE GAS TREATMENT CONTROLS

Commercially available technologies for the control of NO_x after it is formed in the combustion process are currently limited to SNCR and SCR. Both of these processes have seen very limited application in the U.S. for utility boilers. The SNCR process has been used with moderate to high success primarily on smaller industrial combustion sources, fluidized bed combustors in California, and two PC-fired boilers and one larger gas-fired utility boiler, also in California. The SCR process has been investigated in a few pilot- and full-scale utility boiler programs sponsored by EPRI, EPA, and selected utilities. Recently, renewed regulatory efforts to attain ozone air quality standards in Southern California's Los Angeles Basin are including several demonstrations of SNCR and SCR commercial equipment. For example, SCE has planned a total of 5,000 MWe retrofit, with high-energy, urea-based SNCR. Many of these retrofits are already in place and being tested. There are also a total of 40 industrial plants equipped with SNCR, as well as ongoing utility SNCR demonstrations in the states of New York, Colorado, and California. These controls are being evaluated after the utility industry has exhausted most combustion modification retrofit options.

SCR is being used extensively in Japan and Germany with reported successes on all fuels including coal. Several SCR vendors, primarily Japanese vendors, are offering this technology in this country. Application of SCR systems on utilities in the U.S. has been slow because of absence of regulations requiring low-NO_x levels and utility concerns over cost, operational impacts, ammonia slip, corrosion and flyash contamination, and catalyst poisoning with higher sulfur and lower volatility domestic coals. However, SCR has been installed on numerous cogeneration-, reciprocating-engine-, and gas-turbine-based facilities in this country, primarily in California, New Jersey, and other NESCAUM states. For example, the Chamber Works and Lakewood Cogeneration plants in New Jersey operate with SCR controls. Several other states have mandated SCR as Best Available Control Technology (BACT) for engines and turbines. A new 224 MWe PC plant to be located also in New Jersey will be the first SCR coal installation in the United States.



Based on 100 percent retrofit of dry-bottom boilers with combustion controls needed to achieve specified NOx targets

Figure 4-5. Estimates of NO_x reduction from oil- and gas-fired boilers in the NESCAUM region

The following subsections briefly describe these technologies and their application to the NESCAUM boiler inventory.

4.3.1 Selective Noncatalytic Reduction (SNCR)

In the SNCR process, ammonia (NH_3) or urea (NH_2CONH_2) are injected into the convective section of the boiler where the temperature of the flue gas is in the range of 930 to 1,090°C (1,700 to 2,000°F). Within this temperature window, NH_2 radicals from the injected reagent react selectively with NO to form nitrogen and water. The efficiency of these patented processes depends primarily on the temperature of the gas, the mixing of the reagent with the flue gas, and the amount of reagent injected in relation to the concentration of NO_x in the gas. The optimum gas temperature for the reaction is about 950°C (1,750°F). Deviations from this temperature result in a decrease in NO_x reduction efficiency. Therefore, NO_x reductions are very boiler-specific and sensitive to the boiler load. Aside from the ability of SNCR technology to maintain NO_x reduction performance with boiler load, major concerns are NH_3 slip (caused by unreacted reagent) and the operational problems that these emissions can cause when burning sulfur bearing fuels. Additionally, excessive NH_3 can contaminate flyash to the point that it eliminates its resale value. More recently, N_2O has been shown to be a byproduct of SNCR chemistry, primarily when urea-based reagents are used.

Early demonstrations of the SNCR technology utilized Exxon's Thermal $DeNO_x$ process on a Southern California utility boiler. NO_x reductions were limited to 35 to 45 percent due to the inability of the process to follow boiler load, difficulty in controlling the amount of NH_3 injected as the load changed, and inefficient mixing of the NH_3 in the gas stream (Dziegiel, 1983). Significant uncontrolled NH_3 emissions were associated with early applications of the Thermal $DeNO_x$ process. Since that initial demonstration at the LADWP Haynes Unit 4, significant improvements have been made to the Thermal $DeNO_x$ process such that process guarantees are in the 40 to 60 percent NO_x reduction. However, no utility boiler retrofit has taken place since. NH_3 injection has been used on municipal waste combustors and other sources such as industrial boilers and fluidized-bed combustors with significant NO_x reduction success.

Urea injection in the NOXOUT Process has recently been installed on three Southern California oil- and gas-fired boilers. On two boilers, NO_x reductions attributed to urea injection were approximately 30 percent with NH_3 slip of 20 ppm (Abele, 1991). On the third boiler, NO_x reductions were limited to about 20 to 25 percent to minimize the amount of unreacted NH_3. Here the process was found to be very sensitive to the temperature fluctuations due to routine load changes (Jones, 1991). The Long Island Lighting Company (LILCO) is evaluating urea in an oil-/gas-fired utility boiler. Several parametric tests were performed at LILCO's Port Jefferson 185 MWe Unit 3 to optimize the performance of Nalco Fuel Tech's NOXOUT-A process. With a urea injection rate corresponding to a normalized stoichiometric ratio (NSR) of 1.5 to 2.0, NO_x was reduced 50 to 56 percent across the load range, with a 20- to 40-ppm NH_3 slip and N_2O generation corresponding to 10 percent of the NO_x removed (Teetz, 1992).

In another oil-/gas-fired retrofit demonstration, a urea/ammonia injection system by Noell, Inc. was installed at the PG&E Morro Bay oil-/gas-fired 330 MWe Unit 3. Tests showed consistent NO_x reduction efficiencies in the range of 30 to 40 percent. However, NH_3 slip levels exceeded 100 ppm (Teixeira, 1992). In one coal-fired utility demonstration of urea injection, the NOXOUT process was tested on a tangentially-fired boiler. NO_x was reduced from 225 ppm to 165 ppm after application of combustion modifications (Camparato, 1991). In a more recent application of SNCR retrofit on a coal-fired boiler, two-level injection system, by Noell Inc., using high-energy urea was reported to achieve 10- to 30-percent reductions from LNB-combustion-controlled levels (Hunt,

1992). NH_3 slip from Arapahoe 100 MWe Unit 4 was low and N_2O conversion accounted for 10 to 15 percent of the NO_x reduced. New applications are evaluating processes where SNCR can be used in connection with an SCR catalyst to minimize the unreacted NH_3 emissions, reduce the catalyst required and improve performance. These systems await demonstration.

The retrofit of SNCR for utility boilers requires a detailed mapping of the gas flow, temperature and NO_x emissions profiles in the upper regions of the furnace and convective passes of the unit. These profiles should be completed for the entire boiler load range. Based on this information and the available cavities for placement of the reagent injection nozzles, the optimum injection location is selected. Many retrofits will require multiple injection locations to compensate for the rapidly dropping gas temperature with boiler load. This complicates the process monitoring and reagent feedrate control which must be adequately designed to retain NO_x reduction performance and low NH_3 emissions throughout the boiler load range (Jones, 1991).

A principal concern with this technology is its ability to retain NO_x reduction performance over a wide range of boiler loads, with minimal unreacted NH_3 emissions. Such emissions can cause severe operational problems, including air heater fouling, low-temperature corrosion, and plume opacity. For coal-fired power plants, the amount of unreacted SNCR ammonia collected on the flyash can be a significant concern because of landfill restrictions, and loss of revenue from the sale of flyash to cement manufacturers. The NOXOUT technology uses advanced furnace aerodynamic and heat transfer computational modeling coupled with control of the mean droplet size of liquid urea and proprietary additives to optimize NO_x reduction throughout the boiler load range with minimal NH_3 slip.

In summary, SNCR is a commercially available control technology with potential for a 25- to 40-percent additional NO_x reduction beyond levels achieved with combustion modifications already in place. Lower percent NO_x reductions are expected when the initial NO_x levels are low. Therefore, oil- and gas-fired boilers with emissions of 150 ppm attained via combustion retrofits will likely be limited to a maximum of 40-percent reduction using SNCR, commensurate with results obtained at Morro Bay Unit 3. With uncontrolled NO_x emissions, the performance of the urea-based SNCR is estimated to range between 40 and 50 percent, with NH_3 emission slip in the range of 5 to 100 ppm depending on the process selected and type of application. A portion of this NO_x reduction will be changed to N_2O emissions depending on the reagent selected, combustion conditions (CO and HC emission concentrations), and NO_x reduction target.

Generally, the technology is considered applicable to all fuel types and to both controlled and uncontrolled units, but long-term performance and operational impact experience is lacking. Also, concerns over corrosive ammonium sulfate and bisulfate formation with high-sulfur fuels currently limits potential the application to low sulfur fuel-fired power plants to minimize impacts on ash disposal and corrosion/fouling. Furthermore, the complexities of load following favors process applications on boilers that are generally base-loaded.

4.3.2 Selective Catalytic Reduction (SCR)

In the SCR process, gaseous NH_3 along with a carrier gas (typically compressed air) is injected upstream of a catalytic reactor operating at temperatures between 230 and 400°C (450 and 750°F). As in the SNCR process, the NH_3 reduces NO to N_2 and water. NO_x control efficiencies are often in the 70- to 90-percent range depending on the size of the catalyst, the amount of NH_3 injected, the initial NO_x level, and the age of the catalyst. Typically, the reduction efficiency of the catalyst degrades over time as the catalytic surface becomes contaminated or coated with flue gas

particulate and ash. Layers of the initial catalyst have to be replaced routinely to maintain overall performance.

SCR is conceptually applicable to all coal-, oil-, and gas-fired utility boilers. Applications of SCR on both new and retrofit utility boilers have been limited to Japan and Germany, however. Other European countries are planning SCR retrofits to meet new European Community (EC) power plant emission regulations. Appendix E lists current and planned SCR installations on coal-fired boilers worldwide. In the United States, SCR projects for utility boilers have been limited, for the most part, to a few coal and oil demonstrations sponsored by EPRI, EPA, and related utilities (Janik, 1992; Huang, 1992; Guest, 1992; Kerry, 1986; Cichanowicz, 1987). Many of these initial SCR demonstrations have also been discontinued. However, new SCR retrofit projects are being initiated for Southern California utilities, because of increasingly stringent NO_x control requirements in that severe ozone nonattainment area, and by EPRI. SCR has been installed on many gas turbines and reciprocating engine prime movers in cogeneration plants and industrial applications in the United States and abroad. These units are typically based loaded and burn clean fuels.

Japan has about 20 years of full-scale utility experience with SCR. The more recent SCR experience is reported to have significant success. Early concerns about ammonia slip (the amount of unreacted NH_3 leaving the flue gas), the formation of ammonia sulfate and bisulfate, and catalyst poisoning and deactivation have been addressed. Reports of ammonia slip control to levels below 5 ppm are routine (Beherens, 1991, Lowe, 1991). Ammonium sulfates, a principal concern because of the corrosive properties of these compounds, have been reduced with different catalyst formulations that minimize the amount of SO_2 to SO_3 conversion in the reactor (Lowe, 1991). This catalyst property that converts a fraction of the SO_2 to SO_3 is important because of the potentially severe corrosion that can occur with ammonium sulfate compounds. Also, higher SO_3 concentrations increases the dew point of flue gas requiring higher stack temperature and a loss in thermal efficiency. Catalyst life has been reported to range between 4 and 10 years for coal-fired power plants depending on whether the application is in a high or low dust environment. For oil and gas firing, the Japanese report no catalyst degradation for up to 10 years (Lowe, 1991).

Today, SCR is used on more than 100 utility boilers in Japan, 40 burning coal (Nakabayashi, 1987). Some SCR systems are operated on high sulfur (2.5 percent) coal with no performance degradation and low NH_3 slip (Beherens, 1991). Major Japanese catalyst manufacturers are MHI, Kawasaki Heavy Industries (KHI), Ishikawajima Harima Heavy Industries (IHI), Hitachi Ltd. (HTC), Nippon Shokybai, and Hitachi Zosen Corporation (HZC). In Germany, 129 SCR systems have been installed on over 30,000 MWe of utility service (Lowe, 1991). Major European SCR manufacturers are Siemens AG, Haldor Topsoe, and Kraftanlagen AG. Most utility boiler applications have been retrofits including low sulfur coal-burning plants. In the U.S., Norton, Engelhard, W. R. Grace, and Joy Environmental are major suppliers of catalyst. The major U.S. boiler manufacturers also offer Japanese SCR technology. Southern Company Services, Inc., will shortly undertake a test program where 10 different SCR catalysts will be evaluated at the Gulf Power Company's Plant Crist in Florida (Clean Coal Today, 1991). The successful demonstration of these technologies could result in greater acceptance of SCR as a retrofit control option for utility boilers.

The retrofit of SCR on existing power plants can be significant in cost and complexity. Apart from the ammonia storage, preparation, and control monitoring requirements, significant modifications to the boiler convective ducts are necessary. The SCR reactor must be placed in the existing flue gas path where the temperature is sufficiently high for efficient NO_x control. Also, a

reagent feed system must be installed to ensure adequate distribution of NH_3 across the gas flow. Figure 4-6 illustrates the various SCR retrofit arrangements for PC units.

There are two basic locations for the retrofit of the SCR reactor. The first is downstream of the boiler economizer, upstream of the air preheater, where the flue gas temperature is typically optimal for the catalytic reaction to take place. This location, typically referred to as hot-side, is common for oil- and gas-fired boilers and for low-ash coal-fired boilers. The second, for a coal-fired unit, is downstream of any air particulate and acid scrubber, upstream of the induced draft fan and stack. This location, commonly referred to as cold-side, has the advantage that most of the flyash has been scrubbed and in some cases the sulfur has also been reduced. However, because the gas is much cooler, it must be reheated at a high cost to catalyst requirements necessitating additional equipment, such as a regenerative air preheater, for energy recovery. For coal-fired cyclones and wet-bottom units, the tail-end SCR system is most appropriate. Recent improvements in catalyst materials, showing resistance to erosion, blinding and contamination and SO_2 to SO_3 conversion, will make it feasible to consider retrofit upstream of particulate control at significant cost saving over cold-end applications. Some wet-bottom boilers in Germany have been retrofitted with SCR. However, significant catalyst degradation due to arsenic oxide poisoning has been reported (Balling, 1991).

Regardless of the configuration and reactor location, the retrofit of SCR to existing power plants requires significant boiler modification and control system upgrade. The reactor volume typically ranges from about 60 ft^3/MWe for a tail-end retrofit to 120 ft^3/MWe for a high-dust retrofit requiring considerable space for the installation (Borio, 1991). When a high-dust SCR is installed, it is often necessary to also install an economizer bypass to be able to maintain the SCR inlet gas temperature to system requirements when the boiler is operating at part load. The economizer bypass can result in a significant energy penalty. Modifications of the building structure, and sootblower relocations are often necessary because of the tight spaces available. Upgrade of the combustion air fans is always necessary to accommodate the increase in pressure drop. Additionally, induced draft units will require conversion to balanced draft resulting in upgraded fan capacity.

A sophisticated ammonia monitoring and feedrate control system is necessary to maintain consistently high NO_x reductions and low NH_3 slip. Excessive NH_3 slip can cause changes in ash characteristics. For some facilities it may be necessary to relocate the stack and replace the liner and make considerable changes to the powerplant building. These large modifications are often due to little space available between the boiler and stack to install the SCR reactor. Depending on the location of the boiler, precautions are necessary for the ammonia storage tank to abide by local safety codes. Ultimately, the catalyst has to be replaced and the spent catalyst must be land-disposed. In the U.S., this disposal is regulated because of potential environmental hazard due to metal formulations of many catalysts.

In spite of the relatively easier application on oil- and gas-fired utility boilers, SCR has not been retrofitted on U.S. utility boilers except for few demonstrations (Kerry, 1986 and Cichanowicz, 1987). SCE is currently demonstrating an SCR air heater (CAT-AH) supplied by KAH of Germany (Reese, 1991; Reese, 1992). In this configuration, one half of the ABB-CE rotating air heater serving 107 MWe of the oil- and gas-fired boiler has been replaced with a catalytic ceramic surface that will perform as an SCR reactor while retaining the heat transfer properties of the air heater. This arrangement can be used in connection with the SNCR process, where any unreacted NH_3 or urea leaving the SNCR temperature window will reduce NO_x further when passing through the air heater. This retrofit is attractive in that it minimizes the space requirements and boiler modifications. Preliminary results of the SCE demonstration of CAT-AH

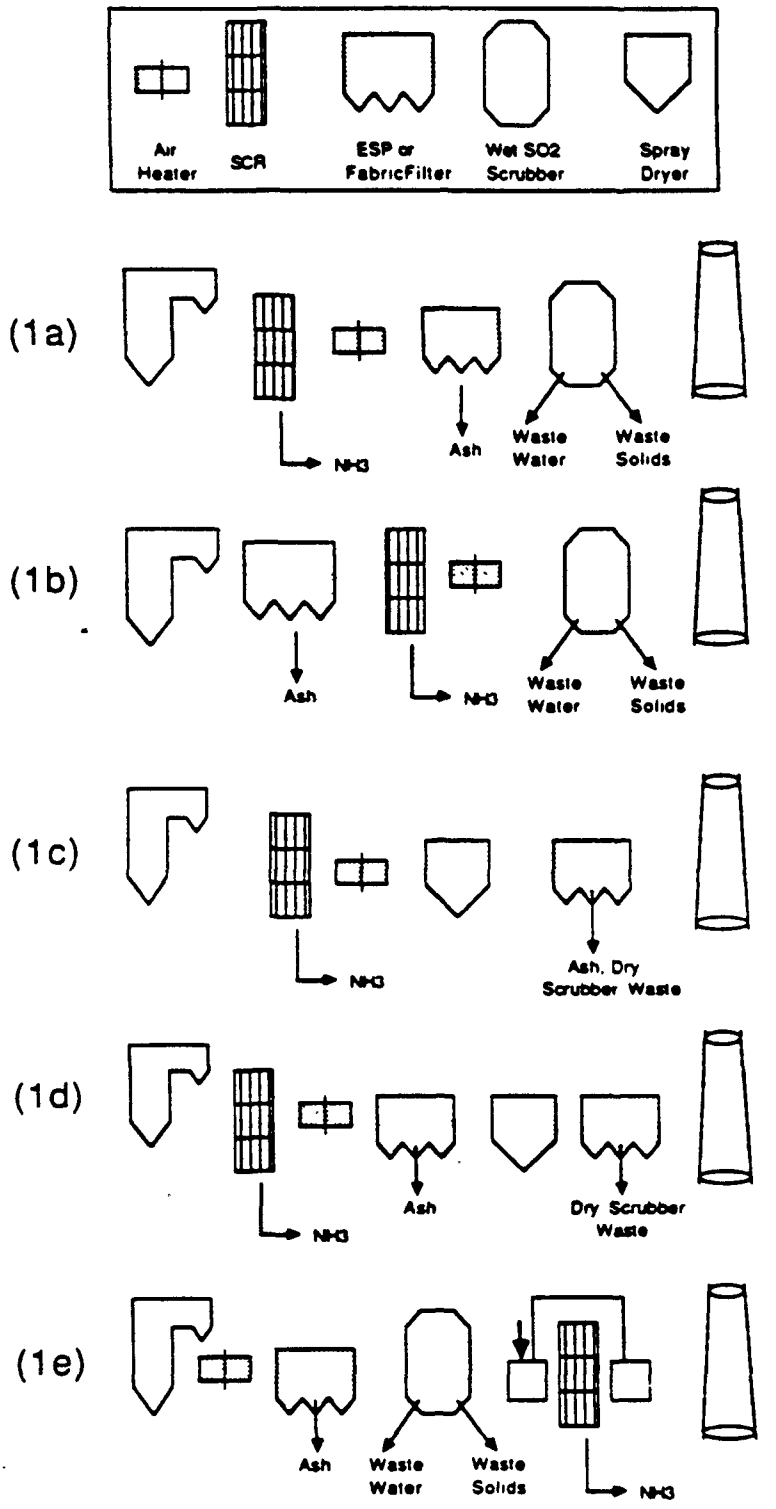


Figure 4-6. Possible SCR configurations (Source: Cichanowicz and Offen, 1987)

has shown NO_x reductions of 50 to 64 percent at full load from combustion-controlled levels of 145 ppm (0.18 lb/MMBtu) (Reese, 1992). However, performance and reliability remain to be demonstrated. Furthermore application of the CAT-AH catalyst of higher sulfur content fuel oils burned in the NESCAUM boiler population remains to be demonstrated.

In conclusion, SCR is a commercially available technology that has been applied to new as well as retrofit utility boilers in Europe and Japan since the early 1970s. However, caution should be used in interpreting these foreign SCR successes because catalyst performance can be severely affected by contaminants present in the coal. U.S. coals have typically higher concentration of some catalyst poisoning agents such as arsenic. NO_x reductions of 70 to 80 percent are possible and are often guaranteed by SCR vendors. Slightly lower NO_x reduction efficiencies are anticipated when the initial concentration of NO_x entering the reactor is low because of combustion controls. Application of these foreign SCR technologies to coal-fired U.S. utilities is likely to be more easily accomplished when the coal burned has low sulfur and low ash. In the NESCAUM inventory, only about one forth of the coal-fired boilers use coal with a sulfur content of 1 percent or less. The use of SCR with higher sulfur coal will result in greater boiler maintenance as few of the units control SO_2. SCR can be retrofitted to gas-fired boilers with little anticipated operational difficulty. Retrofit for oil-fired boilers will require some limitations on the sulfur content of the oil. Approximately two-thirds of the gas and oil-fired boiler inventory in the NESCAUM region operated in 1987 with fuel oil containing less than 1 percent sulfur or less. These units can be considered candidates for SCR retrofit.

4.3.3 Retrofit Potential for the NESCAUM Boilers

Table 4-10 lists estimates of NO_x reduction potential for FGT controls on applicable NESCAUM boilers. For each fuel and boiler firing types, two retrofit cases are considered for the following FGT controls: retrofit on uncontrolled boilers and retrofit on combustion controlled boilers. Uncontrolled levels for PC units are 0.60 and 0.95 lb/MMBtu on the average for tangential and wall units, respectively. Application of SNCR-based controls from these levels would reduce NO_x to a range of 0.50 to 0.65 lb/MMBtu on wall-fired PC boilers (30- to 50-percent reduction), and 0.30 to 0.40 lb/MMBtu (30- to 50-percent reduction) on T-fired boilers. Application of SCR controls at the economizer outlet of PC-fired boilers (hot-side) is estimated to reduce NO_x to a range of 0.20 to 0.30 lb/MMBtu (70 to 80 percent), for wall-fired boilers, and 0.15 to 0.20 lb/MMBtu (also 70 to 80 percent), for tangential boilers. NO_x reduction estimates for cold-side application of SCR are slightly higher because of anticipated better performance with scrubbed flue gas.

As footnote "a" in Table 4-10 indicates, combustion-controlled levels considered for PC-fired units are 0.60 lb/MMBtu, for wall-fired boilers, and 0.45 lb/MMBtu, for tangential units, based on the upper level of NO_x control performance of LNB retrofit projected for NESCAUM units. From these NO_x levels, SNCR controls are anticipated to reduce NO_x to 0.35 to 0.45 lb/MMBtu (25 to 40 percent), for wall-fired boilers, and 0.25 to 0.35 lb/MMBtu (25 to 40 percent), for tangential units. Hot-side SCR controls would reduce NO_x to the 0.10- to 0.20-lb/MMBtu (70- to 80-percent) range, depending on uncontrolled NO_x levels. For gas-/oil-fired boilers, the current baseline levels of dry-bottom units range between 0.30 and 0.45 lb/MMBtu on the average for combined pre- and post-NSPS tangential- and wall-fired boilers, respectively. Estimates of SNCR control performance would reduce these levels to a range of 0.15 to 0.20 lb/MMBtu (30 to 50 percent), for tangential units, and 0.25 to 0.30 lb/MMBtu, for wall-fired units. SCR-based controls on uncontrolled boilers would be capable of lowering NO_x levels to as low as 0.05 to 0.15 lb/MMBtu. When coupled with combustion modifications, SCR is estimated to reduce NO_x to a range of 0.05 to 0.10 lb/MMBtu.

Table 4-10. Flue gas treatment controls

Technology	Achievable Percent NO_x Reduction and Controlled NO_x Levels (lb/MMBtu)		Applicable Boiler Designs	Anticipated Equipment Modifications and System Upgrades
	PC-fired Boilers[a]	Oil- and Gas-fired Boilers[b]		
SNCR (urea or NH_3 based)	Case 1: 30 to 50 (0.50 - 0.65) W 30 to 50 (0.30 - 0.40) T Case 2: 25 to 40 (0.35 - 0.45) W 25 to 40 (0.25 - 0.35) T	Case 1: 35 to 50 (0.25 - 0.30) W 35 to 50 (0.15 - 0.20) T Case 2: 25 to 40 (0.20 - 0.25) W 25 to 40 (0.10 - 0.15) T	Applicable to most boiler designs. Application is more likely on boilers burning low sulfur fuel and noncycling units	Detailed mapping of flue gas needed. Installation of reagent storage, distribution, feedrate control, and injection grids. Installation of CEM and ammonia monitoring system. Possible modification to tube banks and upgrade of air heater washing.
SCR (hot-side retrofit)	Case 1: 70 to 80 (0.20 - 0.30) W 70 to 80 (0.15 - 0.20) T Case 2: 70 to 80 (0.15 - 0.20) W 70 to 80 (0.10 - 0.15) T	Case 1: 70 to 80 (0.10 - 0.15) W 70 to 80 (0.05 - 0.10) T Case 2: 60 to 80 (0.05 - 0.10) W 60 to 80 (0.05 - 0.10) T	Applicable to most boiler design. Application more likely on boilers burning low-sulfur and low-fuel and baseline units.	Reactor installation upstream of air heater with economizer bypass for temperature control. Upgrade fans. Installation of NH_3 storage, distribution, and feedrate control. Installation of CEM system. Cold end equipment relocation possible including building structure and stack
SCR (cold-side retrofit)	Case 1: 75 to 85 (0.15 - 0.25) W 75 to 85 (0.10 - 0.15) T Case 2: 75 to 85 (0.10 - 0.15) W 75 to 85 (0.05 - 0.10) T	NA[c]	Applicable to most boilers including high-sulfur high-ash burning units if equipped with FGD system.	Reactor installation upstream of ID fan and stack. Fans upgrade. Installation of stack gas reheat and heat recovery sections. Installation of reagent storage, distribution, and control systems. Installation of CEM system.

[a] NO_x reductions from pre-NSPS boilers average uncontrolled emissions of 0.95 lb/MMBtu for wall-fired units and 0.60 lb/MMBtu for T-fired units (Case 1) and LNB-controlled levels of 0.60 lb/MMBtu for wall-fired boilers and 0.45 lb/MMBtu for T-fired boilers (Case 2).

[b] NO_x reductions from all listed oil- and gas-fired boilers (pre- and post-NSPS) with uncontrolled NO_x levels of 0.45 lb/MMBtu for wall-fired boilers and 0.28 lb/MMBtu for T-fired boilers (Case 1); and BOOS+FGR - controlled levels of 0.30 lb/MMBtu for wall-fired boilers and 0.20 lb/MMBtu for T-fired boilers (Case 2).

[c] NA = Not applicable. All SCR systems for oil- and gas-fired boilers will use pre-air heater reactor installation.

These levels are based on regulatory targets in California's SCAQMD (Johnson, 1991). These controlled levels are used in Section 6 to calculate the cost effectiveness of these control strategies.

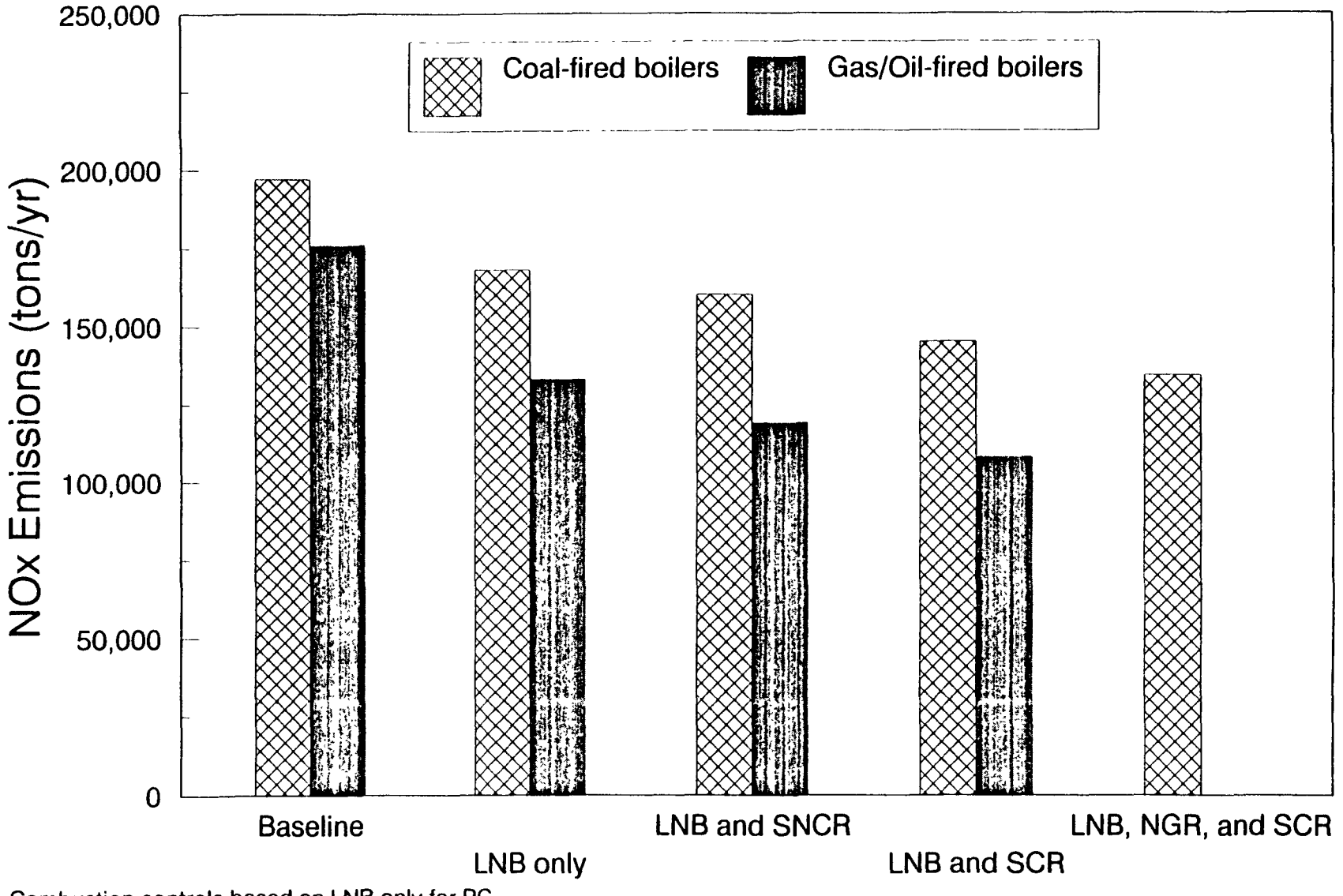
The retrofit target boiler population was selected by excluding all boilers that in 1987 burned fuel with less than 1.5 percent sulfur content. The remaining boiler capacity was further reduced in half to obtain a conservative estimate of the target boiler capacity with favorable dispatch profile, site access, ease of retrofit and fuel properties compatible to SCR systems with hot-side catalysts for PC and oil-/gas-fired units. Figure 4-7 illustrates system-wide NO_x reduction estimated in NESCAUM with contributions from the retrofit of SNCR or SCR controls on 15 and 40 percent of PC- and oil-/gas-fired capacities, respectively. These estimates were based on FGT controls implemented only after combustion control options are exhausted for these units. The figure illustrates that, with SCR retrofit, systemwide NO_x is reduced to 145,000 tons/yr, for PC units, and 108,000 tons/yr, for oil-/gas-fired units. Lower total utility NO_x emissions can be realized by increasing the total capacity of boilers retrofitted with FGT controls above the estimated considered in this study.

It should be pointed out that some PC-fired units will also be targets for SO_2 control as part of the acid precipitation abatement program. These boilers will become candidates for combined SO_2/NO_x FGT controls such as dry or slurry sorbent injection with urea injection with the NOXOUT process or other SNCR processes. Some of the more promising combined NO_x/SO_x control technologies are highlighted next. These technologies are not currently commercially available.

4.4 COMBINED NO_x/SO_x CONTROLS

Recent regulatory and technological developments have resulted in an increased interest in the demonstration of low-cost combined NO_x/SO_x control technologies as alternatives to SCR and FGD gas treatment technologies. The recent CAA Amendments of 1990, and the mandates for acid rain control and attainment of the ozone standard, require a combination of NO_x and SO_2 control strategies for coal-fired powerplants. Although SCR and FGD controls are widely used in Europe and Japan, the widespread acceptance of SCR, particularly in United States, has suffered from concerns regarding the cost and operational reliability with domestic high sulfur coals. Combined NO_x/SO_x control technologies offer the potential for low cost alternatives with capabilities exceeding 90 percent reduction for both pollutants.

Table 4-11 lists several combined NO_x/SO_x reduction processes under various stages of research development and demonstration. Table 4-12 lists processes that are currently being demonstrated under the Clean Coal Technology (CCT) program sponsored by the DOE. Many existing NO_x controls such as LNG and urea injection are also being introduced with other SO_x reduction processes and marketed as combined NO_x/SO_x controls. Appendix C provides schematics of these processes. EPRI has undertaken a study to identify the most promising processes which will then be evaluated in detail for cost and operational reliability (DePriest, 1990). Among the most promising are the NOXSO which uses a high surface area γ-alumina substrate impregnated with sodium to achieve removal efficiencies of 90 percent for SO_2 and 70 to 90 percent of NO_x. The process has been successfully tested at pilot-scale facilities and is undergoing slip-stream full-scale testing at the Ohio Edison Toronto Station (Neal and Bolli, 1991). Other promising technologies are the SNRB, E-Beam, and WSA-SNO_2 processes (DePriest, 1990). In general, combined NO_x/SO_x control technologies are not commercially available. Many are undergoing demonstration programs in the U.S., Canada, and Europe.



Combustion controls based on LNB only for PC and controlled levels to 0.25 lb/MMBtu for oil/gas units. NGR only to coal cyclones & W.B.

Figure 4-7. Estimates of systemwide NO_x reductions with contributions from FGT controls on limited boiler capacity

Table 4-11. Processes under consideration for combined NO_x/SO_x control

Overall Process Group	Process Name
Solid Adsorption/Regeneration	UOP/PETC Fluidized-Bed Copper Oxide
	Process Rockwell Moving-Bed Copper Oxide Process
	NOXSO Process
	Mitsui/BF Activated Coke Process
	Sumitomo/EPDC Activated Char Process
	Sanitech Nelsorbent SO_x/NO_x Control Process
	NFT slurry with NOXOUT Process
Irradiation of the Flue Gas	Ebara E-Beam Process
	Karksruhe Electron Streaming Treatment
	ENEL Pulse-Energization Process
Wet Scrubbing	Argonne/Dravo ARGONNOX Process
	Dow Electrochemical Regeneration Process
	Dow Polychelant/Ultrafiltration Process
	PETC Electrodialysis Process
	California (Berkeley) Ferrous Cysteine Process
Gas/Solid Catalytic Operations	Haldor Topsoe WSA-SO_x Process
	Degussa DESONO_x Process
	B&W $SO_x/NO_x/RO_x/BO_x$ (SNRB) Process
	Parsons Flue Gas Cleanup Process
	Lehigh University Low-Temperature SCR Process
Electrochemical Operations	IGR/Helipump Solid-State Electrochemical Cell
Alkali Injection Operations	Argonne High-Temperature Spray Drying Studies
	PETC Mixed Alkali Spray Dryer Studies
	Battelle ZnO Spray Dryer Process

Source: DePriest, et al., 1990.

Table 4-12. Combined NO_x/SO_x control technologies being evaluated under the CCT program

Technology	Vendor	Retrofit Experience	Reported Performance	Reference
LIMB	Babcock and Wilcox Company	Ohio Edison Edgewater Plant, 104 MWe	50 to 60 percent NO_x/SO_x reduction	PETC Review U.S. DOE
LNS	TransAlta Resources Investment Corp.	Southern Illinois Power Cooperative Marion Plant, 33 MWe	Expected to reduce SO_2 by 90 percent and NO_x to 0.2 lb/MBtu	PETC Review U.S. DOE
SNRB	Babcock and Wilcox Company	Ohio Edison Company R.E. Burger Station, 5-MWe slipstream	Expected to reduce SO_x by 70 percent and NO_x by 90 percent	PETC Review U.S. DOE
WAS-SNO_x	ABB-Combustion Engineering, Haldor Topsoe	Ohio Edison Niles Station 35 MWe slipstream	Expected to reduce NO_x by 90 percent and SO_2 by 95 percent	PETC Review U.S. DOE
GR-SI	Energy and Environmental Research Corporation and Gas Research Institute	Illinois Power Hennepin Plant and City Water, Light and Power Lakeside Station	Expected 70 percent NO_x reduction and SO_2 reduction of 75 percent or more	U.S. DOE
NOXSO	NOXSO Corporation	Ohio Edison Toronto Station 5-MWe	70 to 90 percent NO_x and 90 percent SO_x percent	Haslbeck, 1990

SECTION 5

DESCRIPTION OF COST ALGORITHM AND TEST CASES

This section describes the cost algorithm used and the NO_x control cost retrofit cases evaluated in this study.

5.1 COST ALGORITHM

A simplified cost estimating procedure was developed for this study. The procedure contains all the principal cost elements of the EPA's IAPCS (Maibodi, 1990). The IAPCS was developed by the EPA AEERL to estimate the costs and performance of emission controls for coal-fired utility boilers. Originally patterned after the Tennessee Valley Authority (TVA) cost model, it now incorporates many of the EPRI's Technical Assessment Guide (TAG) cost elements and procedures needed to evaluate the capital and levelized busbar costs and cost effectiveness of power plant equipment, including air pollution control retrofit equipment. Only minor differences exist between the EPRI TAG and EPA's IAPCS costing procedures to the extent that the two methods can be considered essentially equivalent.

The principal cost elements of the IAPCS costing procedure are as follows:

- Process Capital Equipment
- Total Plant Cost
- Total Plant Investment
- Total Capital Requirement
- Fixed Operating Cost
- Variable Operating Cost
- Consumable Costs
- Levelized Capital Charges
- Levelized Busbar Costs
- NO_x Reduction
- NO_x Control Effectiveness

These cost elements are incorporated into a spreadsheet format used to calculate the cost and cost effectiveness of several scenarios. Appendices F and G contain these spreadsheets. The following briefly describes what is included in these various cost elements and the procedures and assumptions used in this study to determine these costs.

The components of capital cost are illustrated in Figure 5-1. The total plant cost (TPC) includes the following:

- Process capital
- General facilities capital
- Engineering and home office overhead

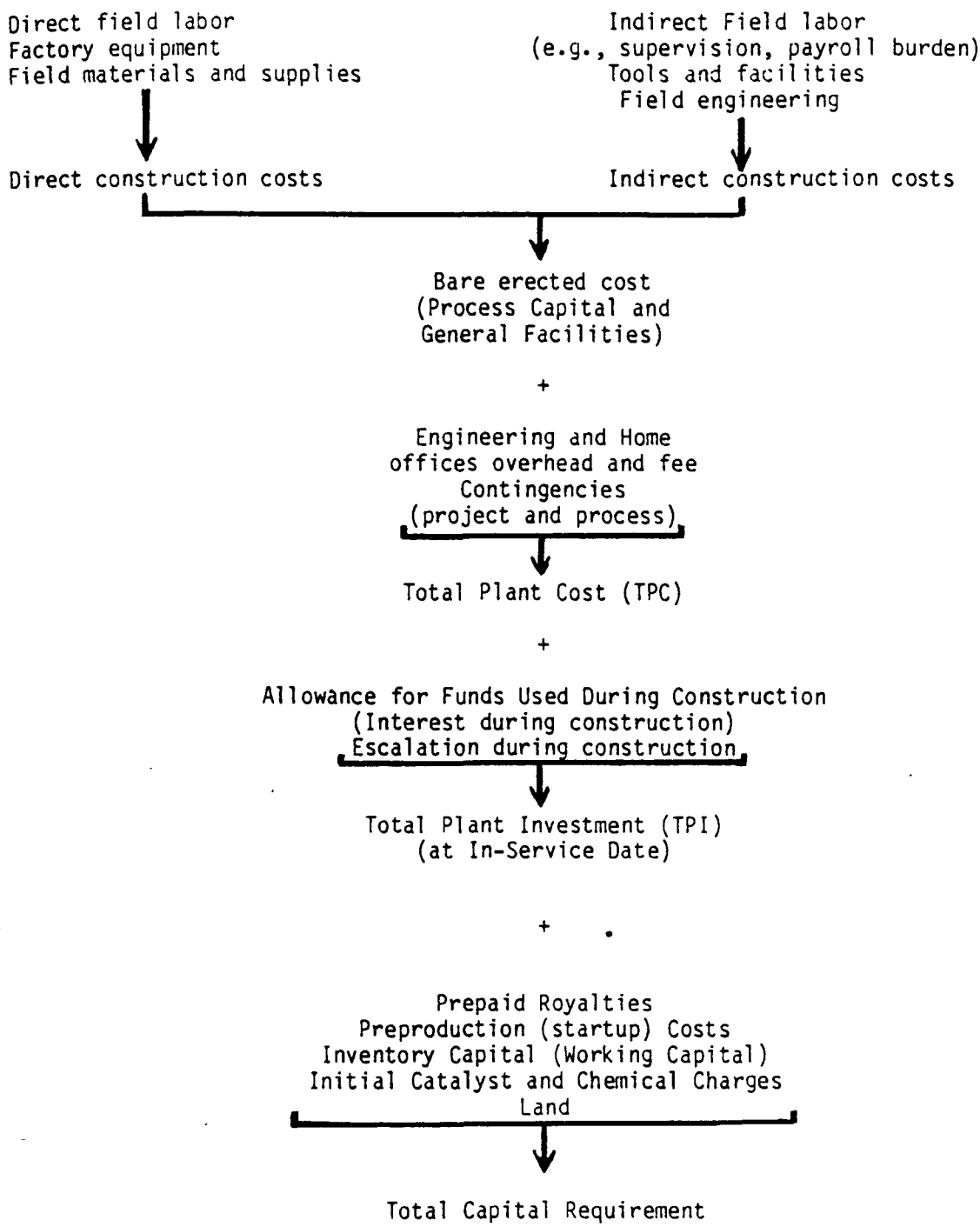


Figure 5-1. Components of capital cost (EPRI TAG, 1982)

- Process contingency
- Project contingency

The process capital is the total constructed cost of all retrofit equipment installed at the site as the result of the NO_x control retrofit. For example, the retrofit of LNB on a coal-fired boiler will require the fabrication and installation of the burners and associated ducting and piping, modifications or replacement of the existing windbox, modifications to the structures including boiler enclosures for access, and other potential upgrades to the pulverizers, fans and boiler monitoring and control systems. Therefore, the installation of a technology may require several individual retrofit components and modifications. The detailed breakdown of the individual costs would provide a measure of the potential effects of key site-specific factors. However, apart from a few exceptions, this cost detail was not available in the open literature. Technology vendors generally decline to provide specific line item costs for a broad study such as this because of the uncertainty associated with site-specific factors and for competitive reasons (Smith, 1991 and Kleisley, 1991). When necessary, capital cost data were normalized to 1991 dollars using published power plant cost indices.

The general facilities include road, office buildings, shops, etc., and are typically taken as 5 to 20 percent of the process capital cost (PCC) according to EPRI cost premises. For this study a 10 percent factor was recommended for most boiler design types (Maibodi, 1990). Engineering and home office overhead fee (EHOF) are costs associated with the retrofit project and typically vary between 10 to 15 percent of the process capital. Ten percent was generally used in this study. The contingencies (process and project) are significant components of the total capital requirement (TCR). The project contingency is intended to cover for the uncertainty in the cost estimate itself, whereas the process contingency addresses the uncertainty in the performance of the retrofit equipment. The EPRI TAG provides guidelines for estimating these costs. The process contingency varies between 10 and 20 percent of the process capital and the project contingency varies between 30 and 40 percent of the process capital plus related expenses. Technologies which have not been demonstrated generally have a higher project contingency. In this study, the highest project contingency (40 percent) was used for selective catalytic reduction (SCR) retrofit on coal-fired boilers. All other technologies were given a project contingency of 30 percent according to IAPCS procedures.

In addition to these costs, the EPRI TAG has provision for the costs associated with the duration of the retrofit project. For retrofit projects exceeding 1 year, additional costs are included in the estimate based on the escalation during that period of time. Because the time required to install the NO_x controls analyzed in this study is estimated to not exceed 1 year, no incremental cost was considered due to escalation. Many LNB retrofits have required 8 to 16 weeks of outage including serious upgrades (Smith, 1991; Laursen, 1992; Hardman, 1992; Sorge, 1992; and Manaker, 1992). This time does not include startup and optimization testing.

The total capital requirement (TCR) used includes additional costs such as royalties and preproduction. Unless royalty costs were reported in the literature or supplied to this study by the technology vendors, no royalties were assumed. Preproduction includes the cost of training of personnel for the operation of the retrofitted technologies. This cost is standardized at 2 percent of the total plant costs (TPC). Land, inventory capital (some has been included in process costs), land, allowance for funds during construction (AFDC), and sales tax were not calculated in this study.

The operating costs are divided between the fixed and variable portions. Both the fixed and variable operating costs includes the increase in operating labor associated with the retrofit

technology, maintenance, and administrative and support costs. For example, the equation from IAPCS used for calculating the operating labor associated with an SCR system is:

$$Operating\ labor \left(\frac{\$}{kW\text{-}yr}\right) = \frac{CF}{0.628}\ (1341 + 5.363\ MW)\ UC_{OL} \left(\frac{1}{1000\ MW}\right) \qquad (5\text{-}1)$$

where CF is the capacity factor (fraction), MW is the boiler rating in megawatts, and UC_{OL} is the unit cost of operating labor in $/man-hr. In conformance with EPRI's TAG, the maintenance cost was set at 2 to 4 percent of the TPC (4 percent for SCR technology). Without further information, the maintenance labor to materials ratio was assumed to be 40/60. The administrative and support labor costs were set at 30 percent of the operating and maintenance labor. The breakdown between fixed O&M and variable O&M is defined by the following equations:

$$Fixed\ O\&M \left(\frac{\$}{kW\text{-}yr}\right) = CF\ (O\&M) \qquad (5\text{-}2)$$

$$Variable\ O\&M \left(\frac{mills}{kW\text{-}hr}\right) = (1 - CF)\ (O\&M) \left(\frac{1000\ mills}{\$}\right) \left(\frac{8760\ hr}{yr}\right) CF \qquad (5\text{-}3)$$

where O&M is the sum of operating labor, total maintenance, and administrative and support labor costs.

Consumables include the incremental fuel used due to thermal efficiency losses or used as part of the process (e.g., for reburning and to reheat flue gas in the SCR cold-side retrofit), catalyst replacement and disposal, NO_x reduction reagent (e.g., urea or ammonia), incremental use of electrical power for fan boosting and pumps, and any water or steam associated with the NO_x reduction process. The equations used for calculating consumables operating costs (in mills/kW-hr) were derived from IAPCS for ammonia, urea, electricity, catalyst replacement, and catalyst waste disposal.

In order to use IAPCS's equation for catalyst replacement, the volume of the replacement catalyst is needed. The following equations were used:

$$\frac{4.762(n_C + n_S) + 0.9405 n_H - 3.762 n_{O_2\ fuel}}{1 - 4.762 \dfrac{\%O_2\ flue}{100}} = \frac{lb\text{-}mol\ flue\ gas}{lb\text{-}fuel}$$

Where (5-4)

$$n_C = \frac{\%C}{1201} \qquad n_H = \frac{\%H}{100.8} \qquad n_S = \frac{\%S}{3206} \qquad n_{O_2\ fuel} = \frac{\%n_{O_2\ fuel}}{3200}$$

Coal (fuel) composition: %C = 72.8%, %S = 2.2%, %H = 4.8%, and $\%O_2$ = 6.2%
Flue gas $\%O_2$ = 3%

$$\frac{lb\text{-}mol\ flue\ gas}{lb\text{-}fuel}\left(\frac{385.3 ft^3}{lb\text{-}mol\ gas}\right)(1000\ MW)(HR)\left(\frac{1}{HV}\right) = \frac{ft^3\ of\ flue\ gas}{hr} \qquad (5\text{-}5)$$

$$Catalyst\ Volume = \frac{Flue\ Gas\ Flowrate\ (ft^3/hr)}{Space\ Velocity\ (1/hr)} = ft^3 \qquad (5\text{-}6)$$

HR is the heat rate in Btu/kW-hr, and HV is the heating value in Btu/lb.

Fuel efficiency losses, reported as an increase in heat rate, result in an increase in fuel consumption. Thermal efficiency losses of 0.5 percent were attributed to all technologies that use burner staging with OFA alone or in combination with other technologies. BOOS only applicable to oil- and gas-fired boilers, was considered to have an efficiency loss of 0.25 percent. Efficiency loss are generally lower, if any, when burning gas because little additional excess air is needed to control CO and HC emissions. LNB vendors generally report little or no adverse impact of LNB when used without OFA or advanced OFA (AOFA) (Vatsky, 1991; LaRue, 1990, Lisaukas, 1987). Efficiency loss of 0.25 percent was used for LNB applications to reflect increase in LOI reported by several retrofits. Details of this effect of LNB retrofit on LOI are provided in Section 7. The retrofit of NGR is reported to result in an increase in heat rate of 0.10 to 0.50 percent (Farzan, 1989; Brown, 1992; and May 1992). A 0.5-percent increase in heat rate was used for this cost analysis.

The amount of NO_x reagent needed for FGT technologies was calculated based on the uncontrolled NO_x levels and the size of the boiler. For example, the quantity of NH_3 needed for SCR application is based on one mole of anhydrous NH_3 for each mole of NO_x in the flue gas. Therefore, the annual usage is determined as follows:

$$NH_3\left(\frac{ton}{yr}\right)\frac{17\ lb\ NH_3}{46\ lb\ NO_2}\left(\frac{NH_3}{NO_x}molar\ ratio\right)(EF)(HR)(kW)\left(\frac{8760\ hr}{yr}\right)(CF)\left(\frac{MMBtu}{10^6\ Btu}\right)\left(\frac{ton}{2000\ lb}\right) \qquad (5\text{-}7)$$

Where EF is the baseline NO_x emission factor in lb/MMBtu, HR is the heat rate in Btu/kW-hr, kW is the boiler capacity in kilowatts, and CF is the capacity factor (fraction). Urea usage was based on using a normal stoichiometric ratio (NSR) of 1.5. The molecular weight of NO_2 is used because emission levels are generally reported in lb NO_2/MMBtu. For SNCR and SCR retrofits, no economic penalty was calculated due to potential loss of revenue from the sale of flyash or increased disposal costs.

Some control technologies may result in the reduction of some consumables. For example, the application of natural gas reburning NGR to a coal burning power plant will reduce the amount of coal by the same amount, on a heating value basis, as natural gas used (typically 15 percent of the total heat input). However, because natural gas is more expensive than coal on a Btu basis, there is a net increase in costs. No cost credit was considered for the reduction in SO_2 emissions with this technology.

Once the amount of consumables was determined from process requirements or from data reported in the literature, these costs were calculated using the boiler capacity and the unit price costs. Table 5-1 shows the unit price costs used in the algorithm. SCR catalyst costs are reported in the literature to range between \$350/ft^3 and \$650/ft^3 (Robie, 1990). In this study, catalyst cost was based on the higher unit price to develop worst-case costs. However, the relationship between

Table 5-1. Unit costs

Cost Item	Unit Cost	Reference
Coal	$45.84/ton	Electric Power Monthly, Mar 91[a]
Oil	$22.85/bbl	Electric Power Monthly, Mar 91[a]
Gas	$2.61/1,000 ft^3	Gas Facts, 1991
Ammonia[b]	$145/ton	Robie, 1990
Urea[c]	$220/ton	BP Chemical, 1991
Electricity	$0.05/kW-hr	Robie, 1990
Catalyst	$370-$600/ft^3	IAPCS, 1988; Robie, 1991
Catalyst Disposal	$315/ton	Robie, 1990
Operating Labor	$21.45/man-hr	Robie, 1990
Solid Waste Disposal	$8.00/ton	IAPCS, 1990

[a]Average price for New England Region.
[b]Used only in the SCR and Thermal $DeNO_X$™ processes.
[c]Used in the NOXOUT™ process only.

cost effectiveness and catalyst unit price is presented to illustrate cost savings associated with lower catalyst costs.

The TCR and the operating costs are levelized to determine the busbar cost and ultimately the cost effectiveness of the retrofit technology. The levelization procedures used in this study follow those of the EPRI's TAG and the EPA's IAPCS with the exception that the levelization in this study was based on the remaining (book) life of the plant rather than a fixed 30-year levelization factor applied in the EPA and EPRI guidelines. Different levelization factors were used to illustrate the incremental costs associated with retrofit of technologies to units that are near retirement age compared to units that will see a longer period of operation.

Utilities have increasingly turned to life extension projects to extend the service life of PC-fired boilers to 50 years, well beyond the 30-year nominal design and economic life of these units (EPRI, 1989). The feasibility of these power plant life extension projects depends on several economic considerations, including the efficiency of the plant, the needed capital investment, and the cost of alternative power supplies. For this study, the book life was based on the assumption that coal-fired power plants have a 50-year service life and oil-/gas-fired boilers have a 60-year service life. Nearly 20 percent of the existing coal-fired boiler capacity in the NESCAUM region has been in service for more than 35 years. For gas-fired boilers, 20 percent of the capacity has seen more than 40 years of service.

The TCR was levelized over the book life by applying the capital recovery (levelization) factor for a uniform series (EPRI TAG). The total operating and maintenance cost (O&M) is not levelized with any factors. The levelized busbar cost is therefore only the levelized capital cost added to fixed and variable O&M, and consumables including fuel, converted to mills/kW-hr.

Figure 5-2 shows the effect of discount rate on the capital levelization (in percent) versus book life (in years) curves for annual discount (interest) rates of 5, 10, and 15 percent. This study used an annual discount rate of 10 percent. Constant-dollar analysis was used because the effect of inflation was not considered. The cost effectiveness, in $/ton of NO_x removed, is calculated based on the reduction in NO_x from the baseline levels divided into the levelized capital cost. NO_x reduction levels are calculated from data presented in Tables 3-4, 4-1, 4-7, and 4-10). Note that for NO_x controls, whose initial process capital is the largest fraction of the levelized cost, much lower costs are seen as the book life of the unit increases. For these controls, the NO_x reduction costs effectiveness will be least attractive for older facilities that are close to retirement.

Table 5-2 lists the principal cost assumptions used to develop the costs of retrofit NO_x controls. For cost calculations, a nominal power plant heat rate of 10,670 Btu/kW-hr (value obtained from averaging all heat rates used in Appendices A and B [coal and oil/gas boilers, respectively]) was used for all boiler test cases. Information on heat rates for all boilers in the NESCAUM region was not available to differentiate between the major boiler design and fuel classes and age groups. Average heat rates calculated with available data were 10,937 Btu/kW-hr, for PC-fired boilers, and 10,558 Btu/kW-hr, for oil-/gas-fired boilers. These heat rates vary according to boiler load and plant age. The boiler scaling factor, used to calculate the cost variability over a range of boiler capacities uses a conventional exponential relationship where the capital cost varies according to the ration of the capacities raised to the 0.6 power, as follows:

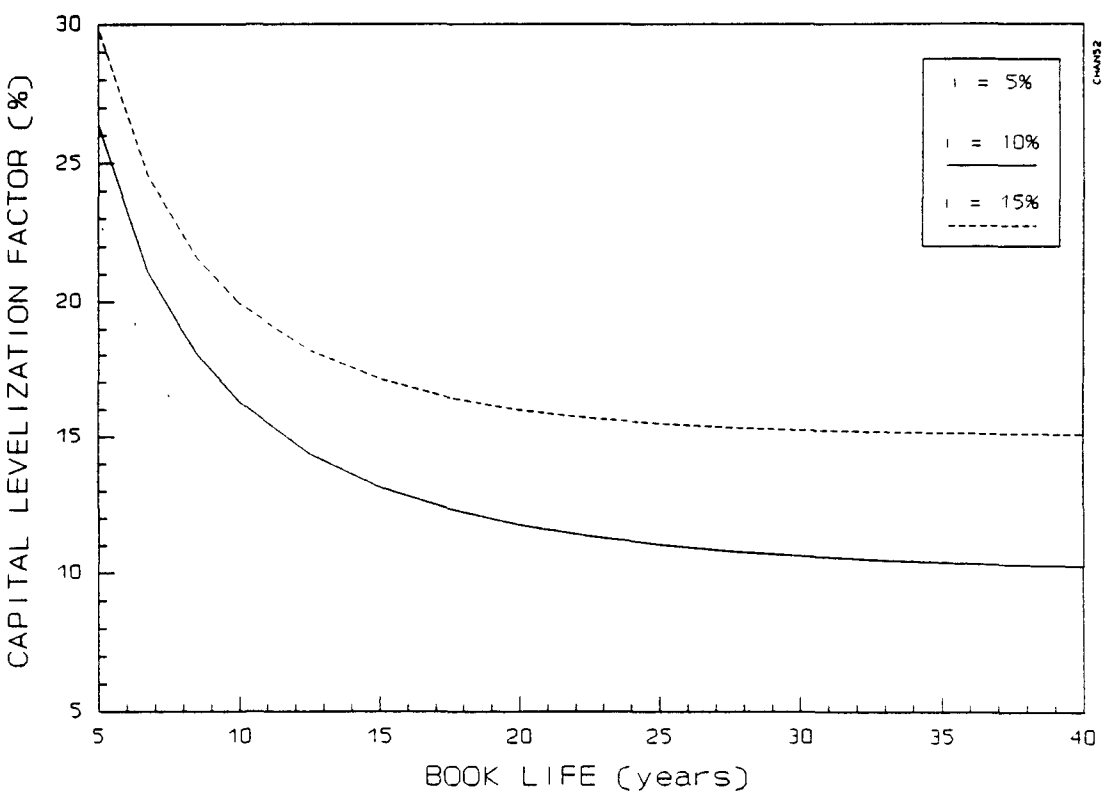


Figure 5-2. Capital levelization

Table 5-2. Cost assumptions[a]

Parameter	Assumed Value	Reference
Gross heat rate	10,670 Btu/kW-hr	
Catalyst life for oil/gas applications	8 years	Johnson, 1991
Natural gas reburn fraction (NGR only)	15%	GRI, 1991
Catalyst life for PC applications	4	Robie, 1990
Oil/gas fuel use ratio	0.65/0.35	Pechan, 1989
Number of catalyst layers	4 years	Maibodi, 1990
Ammonia injection ratio (SCR)	1.0 mole/mole NO	Robie, 1990
Urea injection ratio, NSR (SNCR)	1.5 moles/mole NO	
Boiler scaling factor	$\$/kW_2 = \frac{\$}{kW_1}\left(\frac{MW_2}{MW_1}\right)^{0.6}$	
Boiler service life (coal)	50 years	
Boiler service life (oil/gas)	60 years	
Capital levelization (recovery) factor n = boiler book (remaining) life i = annual discount (interest) rate (i = 0.10)		EPRI TAG
Escalation	0%	EPRI TAG
Allowance for funds during construction (AFDC)	0%	Maibodi, 1990
General facilitates (GF)	10 % of Process capital cost (PCC)	Maibodi, 1990
Engineering home office fee (EHOF)	10% of PCC	Maibodi, 1990
Process contingency (proc)	10% of PCC (20% for NGR)	Maibodi, 1990
Project contingency (proj)	30% of PCC 10% of PCC for cold-side SCR 15% of PCC for hot-side SCR	Maibodi, 1990 Robie, 1990 Robie, 1990
Royalty allowance	0.5% of PCC for SCR 10% to 15% of PCC for SNCR	Maibodi, 1990 Albanese, 1991
Preproduction costs	2% of Total plant costs (TPC)	Maibodi, 1990
Inventory capital costs	0%	Maibodi, 1990
Maintenance costs[b] (MC) (without more detail, 40% of MC is labor)	2% of TPC (4% for SCR)	Maibodi, 1990 EPRI TAG
Administration and support labor	30% of operating and maintenance labor	EPRI TAG

[a]For other O&M costs such as operating labor, electrical consumption, waste disposal, fuel consumption, and catalyst costs, see Maibodi, 1990.
[b]For maintenance costs of NGR and SGR, see Maibodi, 1990.

$$\$_{Case\ 2} = \$_{Case\ 1}\left[\frac{MW_{Case\ 2}}{MW_{Case\ 1}}\right]^{0.6} \tag{5-8}$$

This scaling procedure varies slightly from that used in the IAPCS (Maibodi, 1990).

5.2 COST CASES

Thirty-six boiler NO_x control retrofit cases were evaluated to determine the costs and cost effectiveness of various boiler-control combinations. Tables 5-3 and 5-4 list these cases and the principal sources of data used to develop the capital costs presented in this report. For each of these test cases, parametric variations in the boiler capacity, the age, the capacity factor, and the NO_x control efficiency were evaluated to determine the effect of these variables on the overall costs. The range in the values of these variables to the costs are summarized in Tables 5-5 and 5-6. The range in boiler age and capacity factor were based on the current population profile in the NESCAUM region. The mean, 10th or 20th, and 90th percentile values of the current coal and gas/oil boiler populations were used for these variables. For the boiler capacity, the three cases considered were based on the average, highest and lower boiler sizes within each boiler firing type and fuel category. The lower boiler sizes chosen may not be the lowest in each category due to the exponential growth in costs (and also estimation errors) characteristic of the algorithm. The exponential growth in costs indicates that with smaller boiler sizes, it is economically unfeasible to consider them candidates for NO_x control retrofits.

Although these parametric variation provide a measure of cost variability for boilers with different firing configurations, fuel type, capacity factors, age, baseline NO_x emissions, and control technology, they do not yet address the potential cost variations due to site-specific factors. These factors can add significantly to the variability in cost shown by these parametric variations. The major site-specific factors that can influence the cost significantly are the following (Smith, 1991 and Kleisley, 1991):

- Condition of the existing equipment
- Type of windbox
- Presence of asbestos insulation
- Access to the boiler
- Space availability
- Operating constraints

The condition of the existing boiler refractory, burner, waterwall, windbox, and ancillary equipment at the power plant plays a significant role in the retrofit modifications necessary for many low-NO_x combustion modifications. For example, the windbox air dampers may have been frozen in a given position for many years necessitating the replacement of the windbox even with "plug-in" burner replacements. Pulverizers, fans, waterwall panels may also require replacements even with the most straight forward retrofits depending on condition. Often, older units were equipped with castable windboxes that can not be easily modified and must be replaced entirely. Physical interferences, such as buckstays, headers, and downcomers, can limit available locations for OFA and reburning ports, altering the effectiveness of the technology and decreasing the cost effectiveness (Lisauskas, 1987 and Carnevale, 1989). The relocation of such equipment can be prohibitively expensive (Lisauskas, 1987). The degree of pressure parts changes can also affect the overall retrofit cost significantly (Vatsky, 1989).

Table 5-3. Cost cases for coal-fired boilers

Case No.[a]	Control Technology	Boiler Firing Type	Cost Reference
1	OFA	Wall	Sorge, 1992
2	LNB	Wall	See Figure 6-4
3	LNB[b]	Tangential	Manaker, 1992
4	LNB+OFA	Wall	Sorge, 1992
5	LNB+SOFA[c]	Tangential	See Figure 6-5
6	NGR	Wall	Farzan, 1991 EERC, 1991
7	NGR	Tangential	Farzan, 1991 EERC, 1991
8	NGR	Cyclone	Farzan, 1991 EERC, 1991
9	SNCR	Wall	Nalco, 1992 Hunt, 1992
10	SNCR	LNB-Controlled Wall	Nalco, 1992 Hunt, 1992
11	SNCR	Tangential	Nalco, 1992 Hunt, 1992
12	SNCR	LNB-Controlled[b] Tangential	Nalco, 1992 Hunt, 1992
13	SCR (cold side)[d]	Wall	Robie, 1991
14	SCR (cold side)[d]	LNB-Controlled Wall	Robie, 1991
15	SCR (cold side)[d]	Tangential	Robie, 1991
16	SCR (cold side)[d]	LNB-Controlled[b] Tangential	Robie, 1991
17	SCR (hot side)[e]	LNB-Controlled Wall	Robie, 1991
18	SCR (hot side)[e]	LNB-Controlled[b] Tangential	Robie, 1991

[a]Case No. indicates the order in which cost analyses spreadsheets can be found in Appendix F.
[b]LNB for tangential units is based on LNCFS I with CCOFA.
[c]LNB+SOFA is based on LNCFS Levels II or III.
[d]Cold side SCR retrofit downstream of ESP and FGD with reheat penalty.
[e]Hot side SCR retrofit downstream of economizer with small energy penalty for bypass.

Table 5-4. Cost cases for gas- and oil-fired boilers

Case No.[a]	Control Technology	Boiler Firing Type	Cost Reference
1	BOOS	Wall	Mormile, 1987
2	BOOS	Tangential	Mormile, 1987
3	FGR	Wall	Mormile, 1987
4	FGR	Tangential	Mormile, 1987
5	LNB	Wall	Mormile, 1987
6	LNB	Tangential	Mormile, 1987
7	BOOS + FGR[b]	Wall	Mormile, 1987
8	BOOS + FGR[b]	Tangential	Mormile, 1987
9	LNB + FGR + OFA	Wall	Carnevale, 1989 Yee, 1989
10	LNB + FGR + OFA	Tangential	Carnevale, 1989 Yee, 1989
11	SNCR	Wall	Springer, 1992
12	SNCR	BOOS + FGR-Controlled Wall	Springer, 1992
13	SNCR	Tangential	Springer, 1992
14	SNCR	BOOS + FGR-Controlled Tangential	Springer, 1992
15	SCR	Wall	Johnson, 1991
16	SCR	BOOS + FGR-Controlled Wall	Johnson, 1991
17	SCR	Tangential	Johnson, 1991
18	SCR	BOOS + FGR-Controlled Tangential	Johnson, 1991

[a]Case No. indicates the order in which cost analyses spreadsheets can be found in Appendix G.
[b]Alternatives to BOOS + FGR include OFA + FGR.

Table 5-5. Parametric variations for coal-fired boiler cost cases

Cost Case No.[a]	Control Technology	Boiler Firing Type	Baseline NO_x Emissions (lb/MMBtu)	Controlled NO_x (lb/MMBtu)	Boiler Size (MWe)			Boiler Age (yr)			Capacity Factor		
					L	M	H	20%	50%	90%	10%	50%	90%
1	OFA	Wall	0.95	0.70-0.80	100	200	660	20	30	40	40	65	82
2	LNB	Wall	0.95	0.45-0.60	100	200	660	20	30	40	40	65	82
3	LNB	Tangential	0.60	0.40-0.45	100	200	375	20	30	40	40	65	82
4	LNB+OFA	Wall	0.95	0.35-0.55	100	200	660	20	30	40	40	65	82
5	LNB+SOFA	Tangential	0.60	0.30-0.45	100	200	375	20	30	40	40	65	82
6	NGR	Wall	0.95	0.40-0.50	100	200	660	20	30	40	40	65	82
7	NGR	Tangential	0.60	0.25-0.35	100	200	375	20	30	40	40	65	82
8	NGR	Cyclone	1.28	0.50-0.70	100	200	340	25	30	35	55	73	83
9	SNCR	Wall	0.95	0.50-0.65	100	200	660	20	30	40	40	65	82
10	SNCR	Wall[b]	0.60	0.35-0.45	100	200	660	20	30	40	40	65	82
11	SNCR	Tangential	0.60	0.30-0.40	100	200	375	20	30	40	40	65	82
12	SNCR	Tangential[b]	0.45	0.25-0.35	100	200	375	20	30	40	40	65	82
13	SCR[c]	Wall	0.95	0.15-0.25	100	200	660	20	30	40	40	65	82
14	SCR[c]	Wall[b]	0.60	0.10-0.15	100	200	660	20	30	40	40	65	82
15	SCR[c]	Tangential	0.60	0.10-0.15	100	200	375	20	30	40	40	65	82
16	SCR[c]	Tangential[b]	0.45	0.05-0.10	100	200	375	20	30	40	40	65	82
17	SCR[d]	Wall[b]	0.60	0.15-0.20	100	200	375	20	30	40	40	65	82
18	SCR[d]	Tangential[b]	0.45	0.10-0.15	100	200	375	20	30	40	40	65	82

[a]Case No. indicates the order in which cost analyses can be found in Appendix F.
[b]Boilers controlled with LNB prior to retrofit of FGT technologies.
[c]SCR installed downstream of ESP or FGT with required preheat (cold-side).
[d]SCR installed upstream of air heater with required bypass (hot-side).
L, M, H = Low , medium, and high boiler capacity (from NESCAUM population profile).

Table 5-6. Parametric variations for gas- and oil-fired boiler cost cases

Cost Case No.[a]	Control Technology	Boiler Firing Type	Baseline NO_x Emissions (lb/MMBtu)	Controlled NO_x (lb/MMBtu)	Boiler Size (MWe)			Boiler Age (yr)			Capacity Factor		
					L	M	H	20%	50%	90%	10%	50%	90%
1	BOOS	Wall	0.45	0.30-0.35	100	200	850	15	25	40	10	40	65
2	BOOS	Tangential	0.30	0.20-0.25	100	200	900	15	25	40	10	40	65
3	FGR	Wall	0.45	0.25-0.35	100	200	850	15	25	40	10	40	65
4	FGR	Tangential	0.30	0.20-0.25	100	200	900	15	25	40	10	40	65
5	LNB	Wall	0.45	0.25-0.30	100	200	850	15	25	40	10	40	65
6	LNB	Tangential	0.30	0.15-0.25	100	200	900	15	25	40	10	40	65
7	BOOS + FGR	Wall	0.45	0.25-0.30	100	200	850	15	25	40	10	40	65
8	BOOS + FGR	Tangential	0.30	0.15-0.20	100	200	900	15	25	40	10	40	65
9	LNB + FGR + OFA	Wall	0.45	0.10-0.20	100	200	850	15	25	40	10	40	65
10	LNB + FGR + OFA	Tangential	0.30	0.10-0.20	100	200	900	15	25	40	10	40	65
11	SNCR	Wall	0.45	0.25-0.30	100	200	850	15	25	40	10	40	65
12	SNCR	Wall[b]	0.30	0.20-0.25	100	200	850	15	25	40	10	40	65
13	SNCR	Tangential	0.30	0.15-0.20	100	200	900	15	25	40	10	40	65
14	SNCR	Tangential[b]	0.20	0.10-0.15	100	200	900	15	25	40	10	40	65
15	SCR[c]	Wall	0.45	0.10-0.15	100	200	850	15	25	40	10	40	65
16	SCR[c]	Wall[b]	0.30	0.05-0.10	100	200	850	15	25	40	10	40	65
17	SCR[c]	Tangential	0.30	0.05-0.10	100	200	900	15	25	40	10	40	65
18	SCR[c]	Tangential[b]	0.20	0.05-0.10	100	200	900	15	25	40	10	40	65

[a]Case No. indicates the order in which cost analyses can be found in Appendix G.
[b]Boilers controlled with BOOS + FGR or LNB + FGR prior to retrofit of FGT technologies.
[c]SCR installed upstream of air heater with required bypass.
L, M, H = Low , medium, and high boiler capacity (from NESCAUM population profile).

Some older boilers were enclosed in power plant buildings. These enclosures can significantly add to the complexity of the retrofit (Smith, 1991). When castable windboxes must be replaced because of low-NO_x burner retrofits, it is sometimes necessary to tear down the building to allow access to and removal of the windboxes. Such large modifications can result in the removal of asbestos-insulated ducts and piping, resulting in a significant increase in the cost of disposal (Smith, 1991 and Carnevale, 1989). The available space near the power plant is also critical to the cost for some retrofit technologies such as SCR. Because of such space restrictions, for example, SCE has reported SCR retrofit costs for some of the facilities as high as twice the estimates by local regulatory agencies (Johnson, 1983). Operation of the boiler and its duty cycle also influences the retrofit cost and cost effectiveness. In most applications, the NO_x reduction performance of combustion modification technologies and noncatalytic flue gas treatment processes varies with boiler operating loads. Although on a mass emission basis emissions are lower at lower loads, the percent of NO_x reduction attributed to the retrofit technology is generally less than at higher loads, unless the control was specifically designed to operate at reduced heat input rates.

SECTION 6

COST OF NO_x CONTROLS

The costs presented here are based on cost data reported in the open literature for similar retrofit cases, or, when available, on estimates obtained directly from technology vendors and users. However, it is important to point out that actual retrofit costs are quite dependent on several site-specific factors, as discussed in Section 5. Because of this dependence, the costs presented here should not be interpreted as applicable to any specific power plant within the NESCAUM utility boiler population. By evaluating several cost cases based on boiler size, age, and capacity factor, we have attempted to develop ranges in NO_x control costs that encompass some of the uncertainties due to site-specific factors. However, site-specific considerations could significantly alter the estimates presented here. To develop actual costs for specific power plants, a detailed analysis is necessary of the type and condition of the existing equipment, its layout, the fuel type, and the boiler operating characteristics. Additionally, some sites may incur costs for replacement power if retrofit of controls exceeds scheduled outages. The current regulatory schedule mandated under Title I of the CAAA calls for many retrofit NO_x controls to be in place by May 1995. Because of the anticipated volume of retrofit equipment to be engineered, procured, installed, and tested during this short time, an inflationary factor is anticipated to result in actual costs above the estimates presented here. Evaluating the effects on projected costs of these site-specific factors, and global market forces, was beyond the scope of this study.

Combustion modification controls for NO_x reduction on existing coal-fired utility boilers have been applied only in the past few years. Therefore, retrofit experience and actual costs of these controls have only been documented recently. Ongoing commercial retrofit and demonstration projects are generating new information on performance, cost, and operational impacts. For oil- and gas-fired boilers, the retrofit experience and documented costs is based principally on data reported by California utilities that have been the target of NO_x reduction regulations for the past 15 years. Many of the combustion modifications considered in this study for oil- and gas-fired boilers in the NESCAUM region have been in use for several years on SCE, LADWP, SDG&E, and PG&E boilers in California. Because of the recent passage of more stringent NO_x rules by the SCAQMD, these utilities are now evaluating the least-cost options using second- and third-generation retrofit controls, including several flue gas treatment options.

This section presents the cost estimates of retrofit control options evaluated and reported in Section 4 of the report. Capital costs reflect those reported in the literature or obtained directly from technology vendors. All capital costs are escalated to first quarter 1991 dollars. Where several sources of data are available for these costs, a comparison of the costs developed in this study with costs reported elsewhere is made. The procedure for developing levelized busbar costs relies on available information on consumables, such as fuel from efficiency loss and NO_x reduction reagents, and levelization factors for capital cost based on EPRI premises, as discussed in the previous section. Cost-effectiveness results include estimates of NO_x reduction potential based on information presented in Section 4.

6.1 COMBUSTION MODIFICATIONS FOR PC-FIRED BOILERS

Combustion modifications for PC-fired boilers include OFA, LNB, LNB+OFA, and natural gas reburning (NGR) or pulverized-coal reburning. For reburning cost analysis, only NGR was evaluated because there is a larger experience base with this reburning fuel. The following sections detail the retrofit costs of these control options for coal-fired power plants. Appendix F provides details of the various cost elements and calculations based on the simplified algorithm developed for this study.

6.1.1 Overfire Air (OFA)

OFA is considered a first-generation control option that was included in some new boiler designs to comply with NSPS limits (LaRue, 1990; Lisauskas, 1989). Many of these first-design OFA ports, however, have remained closed because of the ability of these units to comply with NSPS limits without their use. More recently, AOFA systems have been investigated. These systems rely on improved control and better penetration for improved performance. AOFA is generally never considered without the use of LNB.

In this section, OFA is defined as the installation of overfire air ports, separate and above the existing windbox, to provide a separation between the primary burner zone and the staged air needed for complete combustion. For tangential boilers, this type of OFA is called SOFA to distinguish it from CCOFA, inherent to most T-firing systems. This distinction is not necessary for wall-fired boilers because OFA is always injected separate from the existing windbox. In both cases, a new windbox and associated ducting and control system are required, with waterwall modifications, to permit penetration of secondary air into the furnace. Some vendors of this technology may require only the extension of the existing windbox (Lisauskas, 1989). Although retrofit experience is limited, it is generally accepted that the retrofitting of this technology will require a separate windbox, and that the amount of OFA used is limited to 20 to 30 percent of the total combustion air because of concerns with LOI, corrosion, and other operational impacts.

Current OFA systems are capable of NO_x reductions in the 15 to 30 percent range, depending on the initial uncontrolled NO_x level, the degree of air staging, and firing configurations. Typically, the higher degree of NO_x reduction is achieved with higher uncontrolled levels of NO_x. The use of OFA is often associated with decrease in thermal efficiency due to an increase in unburned carbon (UBC) in the flyash and a requirement for higher overall excess oxygen levels that contribute to an increase in the dry gas heat loss. Figure 6-1 illustrates the increase in UBC with AOFA experienced for a tangential boiler retrofit. These losses in efficiency contribute to the total cost of the retrofit. For this cost analysis an efficiency loss of 0.5 percent was assumed for all retrofit cases involving the use of OFA or AOFA with or without LNB.

Figure 6-2 illustrates the calculated cost of OFA for pre-NSPS wall PC-fired boilers. The figure shows both the total capital requirement (which includes process and project contingencies) and the busbar cost. The cost effectiveness is shown in Figure 6-3 as a band in cost for each boiler size to illustrate the effect of a range in NO_x reduction from 0.95 lb/MMBtu to 0.8 and 0.7 lb/MMBtu. The data are for a range in boiler capacities, each with a book life of 20 years and a capacity factor of 65 percent. The estimates indicate that the reduction of 15 to 25 percent of the NO_x estimated for wall-fired boilers with OFA will cost approximately from about $12/kW to $25/kW depending on boiler size with a busbar of about 0.40 to 0.7 mills/kWh and a resulting cost effectiveness ranging from about $300 to $900/ton of NO_x removed.

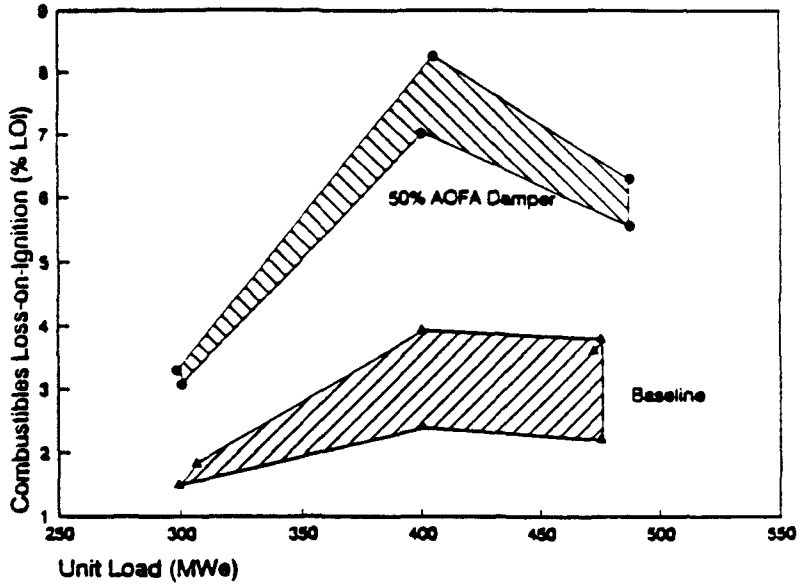


Figure 6-1. Flyash combustibles losses from parametric testing with AOFA (Wilson, 1990)

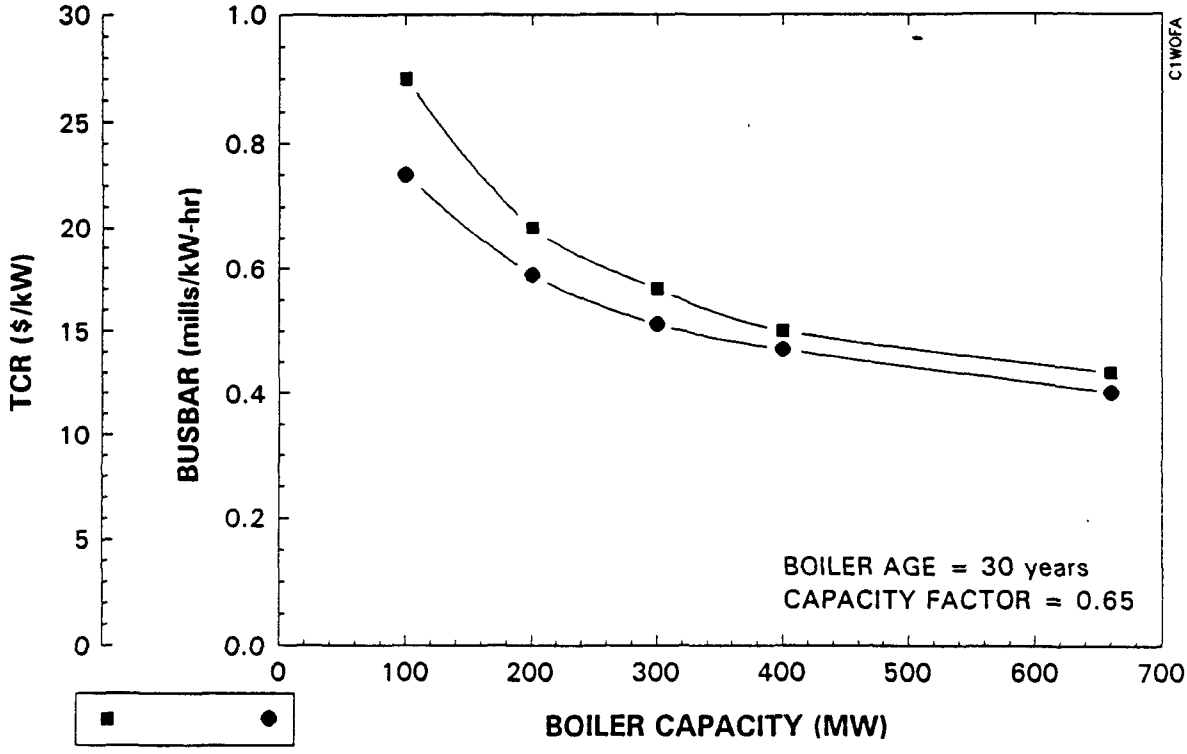


Figure 6-2. Total capital requirement and busbar cost of OFA retrofit for wall-fired PC boilers

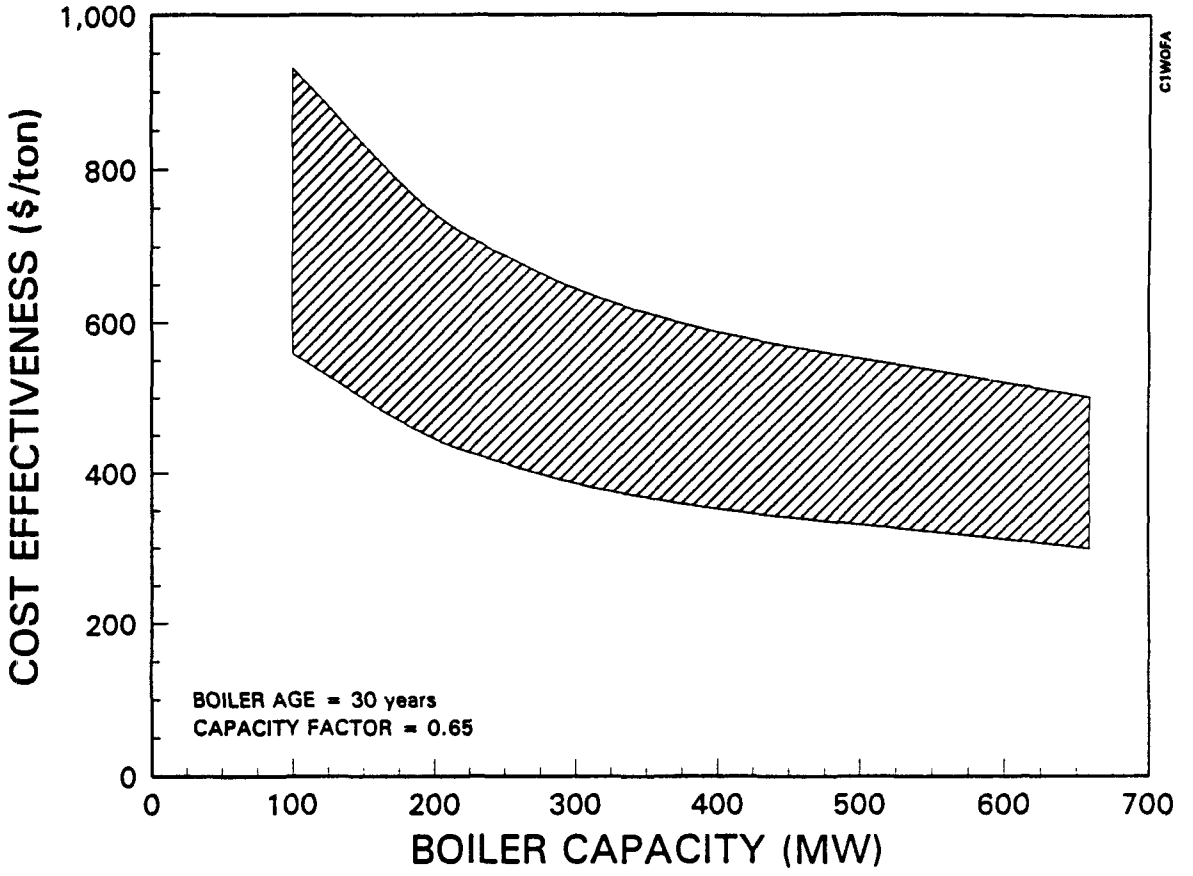


Figure 6-3. Cost effectiveness of OFA retrofit for wall-fired PC boilers

6.1.2 Low-NO_x Burners (LNB) for Wall-Fired Units and LNB+CCOFA for T-Fired Units

LNB is the centerpiece of all major NO_x reduction retrofit programs for PC-fired boilers. The category of LNB encompasses a wide range of burner modifications and retrofit equipment designed to reduce NO_x according to the requirements of the utilities and within the limitations of the technology and the boiler operational constraints. The technology has undergone several improvements over the years. More recent results of several utility boiler retrofits, including some long-term measurements, have shown that LNB+OFA for wall-fired boilers can achieve reductions of 35 to 55 percent, to levels in the range of 0.45 to 0.64 lb/MMBtu (see Section 4 for details).

For tangential boilers, LNB designs vary from minor equipment modifications of the LNCFS Level I burner to more significant modifications of the LNCFS Levels II and III and PM systems that incorporate SOFA systems. Controlled NO_x levels for LNCFS with SOFA on two retrofits are reported to range between 0.28 and 0.32 lb/MMBtu (Hunt, 1991). For PM burners, early tests on the only retrofit demonstration to data in the United States show controlled NO_x levels to as low as 0.25 lb/MMBtu (Wilson, 1990). All these LNB designs use OFA or AOFA. For this study, LNB and LNB+OFA controlled NO_x levels from tangential boilers were estimated to range between 0.30 and 0.45 lb/MMBtu based on recent reports of control efficiency and average uncontrolled levels for T-fired boilers in NESCAUM.

The reductions in NO_x are often commensurate with the degree of modification to the existing equipment. For example, modification or replacement of existing pulverizers to increase coal fineness can provide additional NO_x reduction. Better air/fuel distribution is also necessary to improve overall boiler efficiency and provide needed flexibility in boiler operation and fuel mix. The discussion in this section is limited to cost estimates for LNB retrofit on wall-fired boilers. LNB retrofit costs for tangential boilers are discussed in the following section on LNB+OFA because most T-fired retrofits will likely be equipped with SOFA, which is responsible for most of the NO_x reduction capability of the LNCFS burner configuration.

Table 6-1 lists the LNB and LNB+OFA installation costs of several recent retrofits. Figures 6-4 and 6-5 plot these reported costs versus boiler size for wall-and tangential boilers, respectively. The best fit power curve was taken as the basis for the total plant costs for these units. For example, the TPC for LNB retrofit for wall-fired boilers was selected at $15/kW for a 400 MWe boiler. For T-fired units, the cost reported by TVA for Galletin Unit 4 was selected as the total capital requirement (TCR) for LNB+CCOFA on a 288-MWe boiler. For the combination of LNB+OFA, the recent estimates for Hammond Unit 4 provided cost basis for wall-fired units. For T-fired boilers, the cost of retrofitting PSC Cherokee 350 MWe Unit 4 was selected as the basis for LNCFS II or III burner systems. These LNB+OFA costs are discussed in greater detail in the next section. It is apparent that, beside boiler capacity, the cost of LNB can vary significantly from site to site, often depending on the degree of additional modifications to existing equipment planned or needed as part of the retrofit.

Table 6-2 lists retrofit costs reported at an earlier date for the CF/SF LNB on several boiler types. These reported costs vary from $4.0/kW to $9.3/kW. Table 6-3 lists retrofit costs developed by another major boiler manufacturer (Lisauskas, 1987). The first two lines in this table illustrate the variation anticipated in the capital cost of LNB, even in these early estimates. Estimates for the cost to replace the existing burner with a new LNB was predicted to range between $4.6/kW and $8.7/kW (1983 dollars) for boilers in the range of 140 to 400 MWe. Even after escalation to 1991 dollars, a comparison with data shown in Figures 6-4 and 6-5 shows that these early estimates of LNB costs have proven lower than more recent costs.

Figures 6-6 and 6-7 illustrates the costs calculated in this study for LNB retrofitted to wall-T-fired boilers, respectively. The TCR for LNB retrofitted on boilers from 680 to 100 MWe capacity ranges from $14/kW to about $27/kW. As shown in Table 6-1, several of the reported costs fall near estimates presented in Figure 6-6. For example, TVA's Johnsonville 150 MWe Unit 8 has a reported cost of $32/kW, comparable to levels shown in Figure 6-6. Also shown in Figure 6-6, the cost of LNB is estimated to increase significantly for smaller units less than 150 MWe. The busbar cost includes an efficiency loss of 0.25 percent. For T-fired units, the cost of LNB+CCOFA is considered comparable to that of wall-fired boilers. Estimates shown in Figure 6-7 show a range in cost from about $20/kW $33/kW for a range in capacity of 375 to 100 MWe.

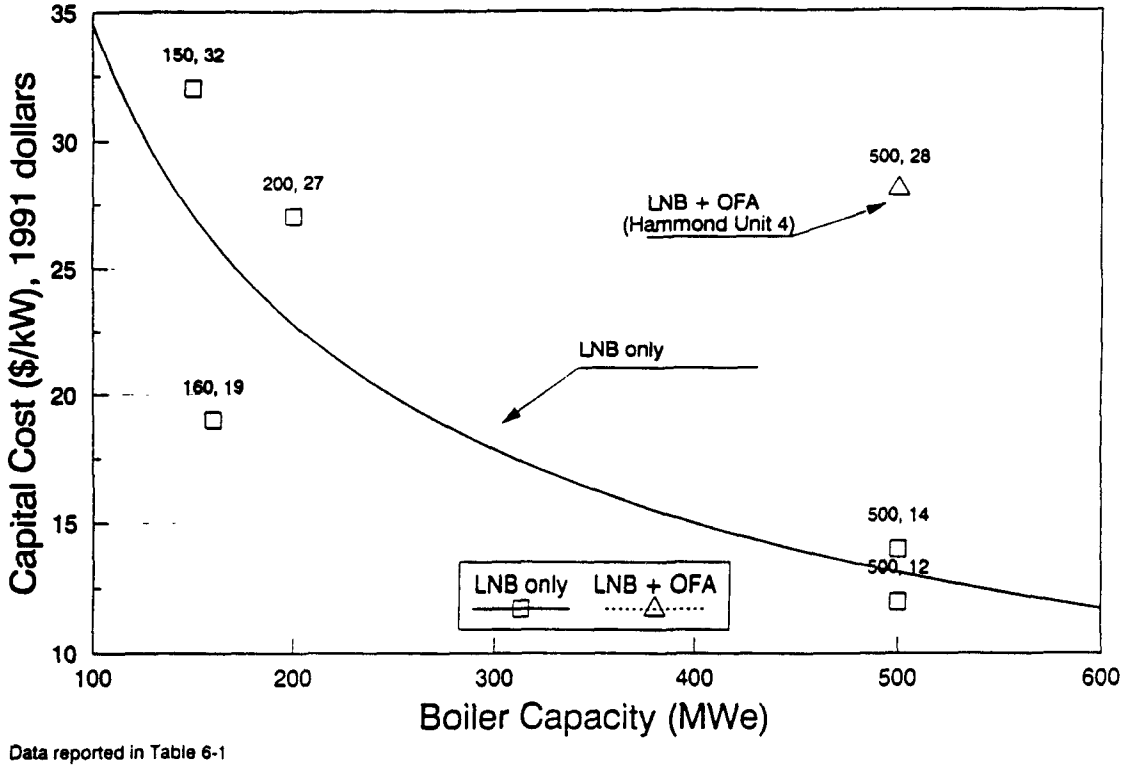
Figure 6-8 illustrates the range in cost effectiveness for LNB retrofit for wall and tangential units. The range in boiler capacities were selected from the boiler population profile. The cost per ton of NO_x reduced is higher for T-fired boilers principally because NO_x reduction, on a lb/MMBtu basis, are lower for this design category. The shaded part of the graphs illustrates the uncertainty in the overall NO_x reduction, reported in Table 4-1.

Cost effectiveness ranges from less than $200/ton to for large wall-fired boilers with a current emission factor of 0.95 lb/MMBtu to nearly $1,000/ton for T-fired boilers of 100 MWe

Table 6-1. Recent LNB and OFA installed costs for PC-fired boilers

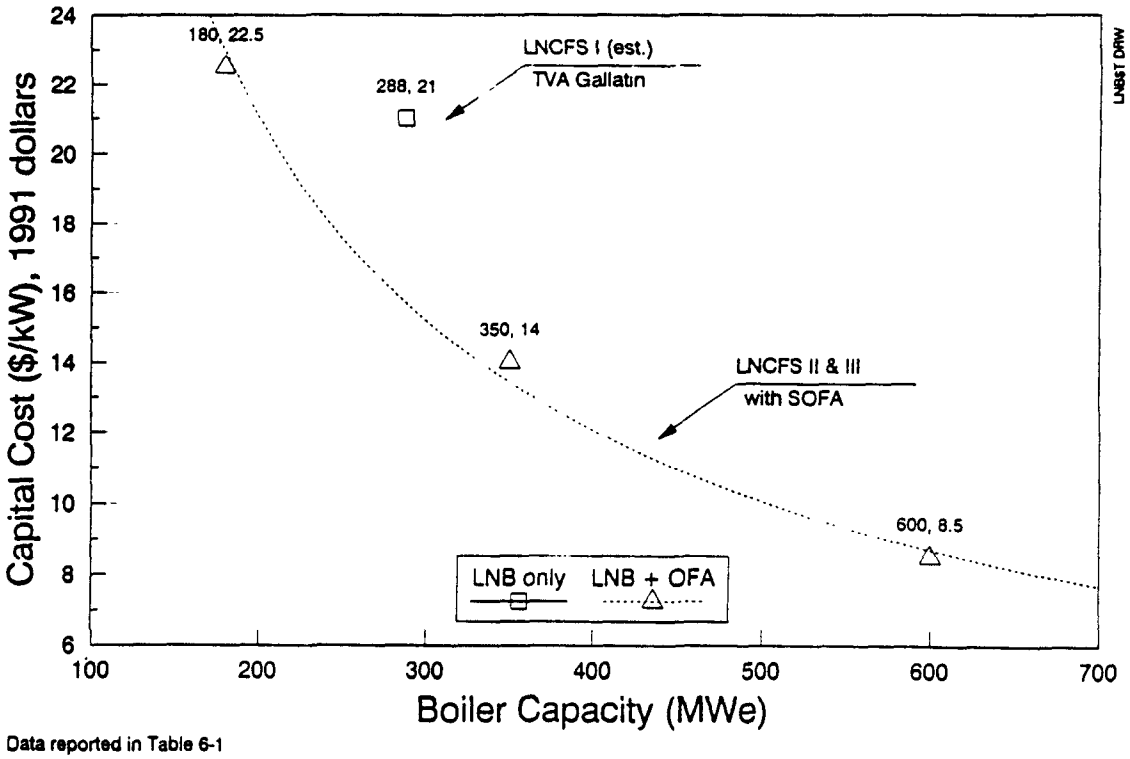
Firing Configuration	Boiler Identification and Size	Reported Capital Cost	Retrofit Schedule	Comments	Reference
Wall- and opposed-fired boilers	GPC Hammond 500 MWe Unit 4 (CF/SF)	$14/kW	8 to 10-week outage	Retrofit accomplished during planned outages	Sorge, 1992
	GPC Hammond 500 MWe Unit 4 (CF/SF+OFA)	$24/kW	8 to 10-week schedule	Estimate of cost does not include several equipment modifications necessary after initial retrofit	Sorge, 1992
	PSC Cherokee 160 MWe Unit 3 (IFS)	$19/kW	10-week outage length	Several modifications of equipment necessary after startup	Hunt, 1992
	TVA Colbert 200 MWe Unit 3 (CF/SF)	$27/kW	8-week outage	Optimization testing underway	Manaker, 1992
	TVA Johnsonville 150 MWe Unit 8 (CF/SF)	$32/kW (est)	8-week outage	Optimization testing underway	Manaker, 1992
	500 MWe reference cell boiler (LNCB)	$8-12/kW	As little as 5 weeks	Estimate provided by vendor with ease of retrofit	Laursen, 1992
Tangential-fired boilers	TVA Gallatin 288 MWe Unit 4 (LNCFS I)[a]	$21/kW (estimate)	Scheduled for retrofit in 2-month period	Not yet in place	Manaker, 1992
	UE Labadie 600 MWe Unit 4 (LNCFS II)[b]	$8.5/kW	Installed during 8-week outage	Retrofit followed by 3 to 4 weeks for tuning delayed because of LNCFS equipment problems	Smith, 1992
	PSC Cherokee 350 MWe Unit 4 (LNCFS II and III)[b]	$11.50/kW to $14/kW	Estimated 8-week outage retrofit	Minor equipment problems reported over 18-month period, attributed to LNCFS	Hunt, 1992
	GPC Lansing Smith 180 MW Unit 2 (LNCFS II and III)[b]	$22.5/kW	Estimated 8-week outage retrofit	Some equipment replacement necessary after retrofit	Hardman, 1992

[a]Firing systems without SOFA.
[b]Includes firing systems with SOFA such as LNCFS Level II and III and PM burner.



Data reported in Table 6-1

Figure 6-4. Capital cost of LNB and LNB + OFA for wall-fired PC boilers



Data reported in Table 6-1

Figure 6-5. Capital cost of LNB with CCOFA and LNB + SOFA for T-fired PC boilers

Table 6-2. Retrofit material costs

MWe	No. of Burners	Burner Modification		$/kW
		Type	Type[a]	
525	24	Circ.	1	4.0
650	24	Circ.	1	4.3
600	40	Cell	1	6.0
600	40	Cell	2	7.5
800	48	Circ.	1	5.4
800	48	Cell	3	9.3

[a]1 = Burner "Plug-in."
2 = Burners + panels for vertical spread.
3 = Burners + panels + convert to one mill/row.
Source: Vatsky, 1990.

Table 6-3. Summary of Riley's economic evaluation for LNB

	Case A[a]		Case B[b]		Case C[c]		Case D[d]	
	Capital Cost	Levelized Cost	Capital Cost	Levelized Cost	Capital Cost	Levelized Cost	Capital Cost	Levelized Cost
LNB								
Coal nozzle retrofit	2.8	0.10	1.4	0.05	2.1	0.08	1.4	0.05
Total burner replacement	8.7	0.32	4.6	0.17	5.4	0.19	4.8	0.17
LNB plus conventional OFA	11.6	0.42	6.3	0.23	7.1	0.26	6.0	0.22
LNB plus advanced OFA	17.8	0.80	11.3	0.51	13.8	0.62	14.9	0.67
LNB plus reburning	21.5	0.97	13.5	0.57	53.2	2.40	18.3	0.82
Capital Cost - $/kW								
Levelized Cost - mills/kWh (30-yr average)								

[a]Case A: 140 MWe, front-fired, four burner rows, no existing OFA ports.
[b]Case B: 400 MWe, front-fired, four burner rows, no existing OFA ports.
[c]Case C: 360 MWe, opposed-fired, two burner rows, no existing OFA ports.
[d]Case D: 360 MWe, opposed-fired, three burner rows, with existing OFA ports.
Source: Lisauskas, 1987.

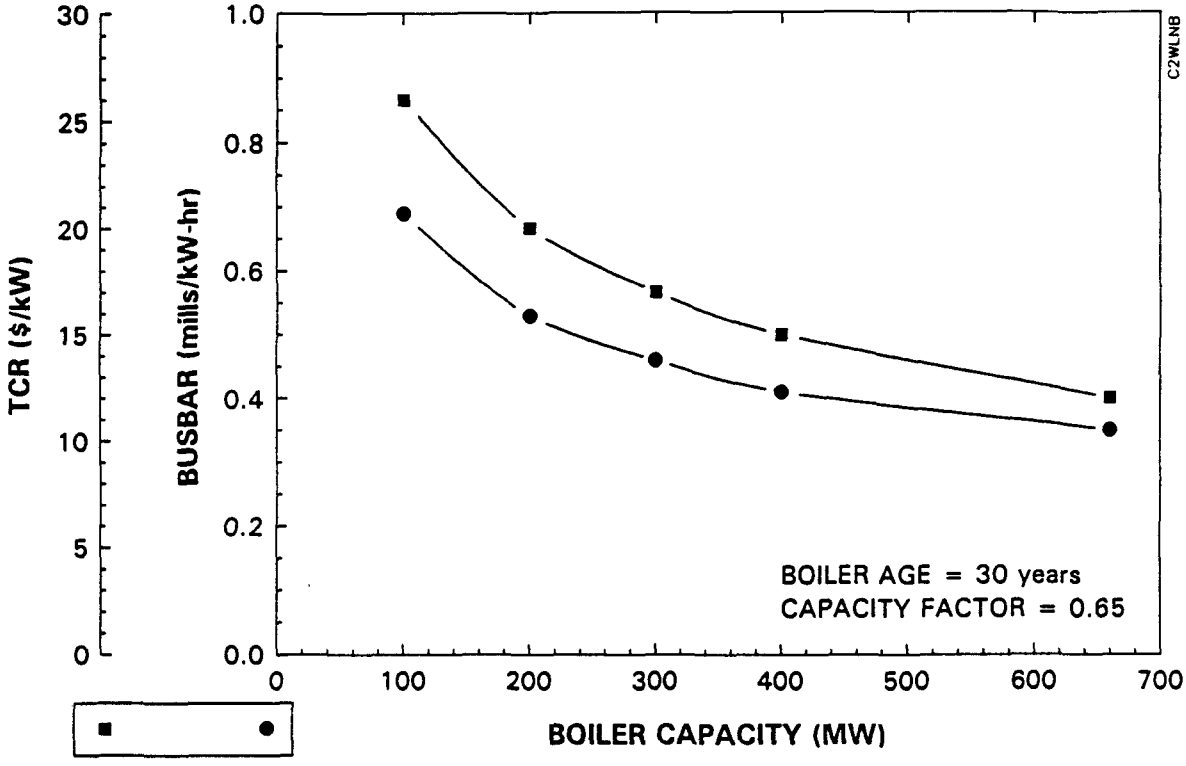


Figure 6-6. Capital and busbar cost of LNB retrofit for wall-fired PC boilers

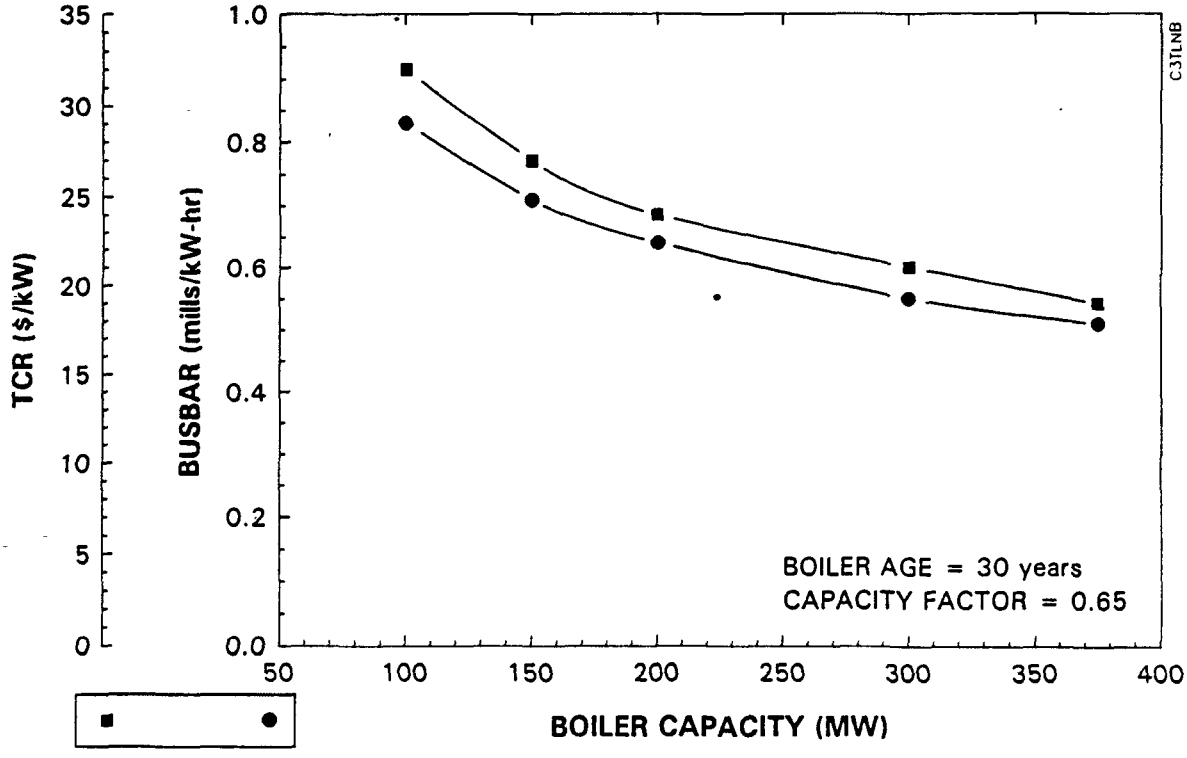


Figure 6-7. Capital and busbar cost of LNB+CCOFA retrofit for T-fired PC boilers

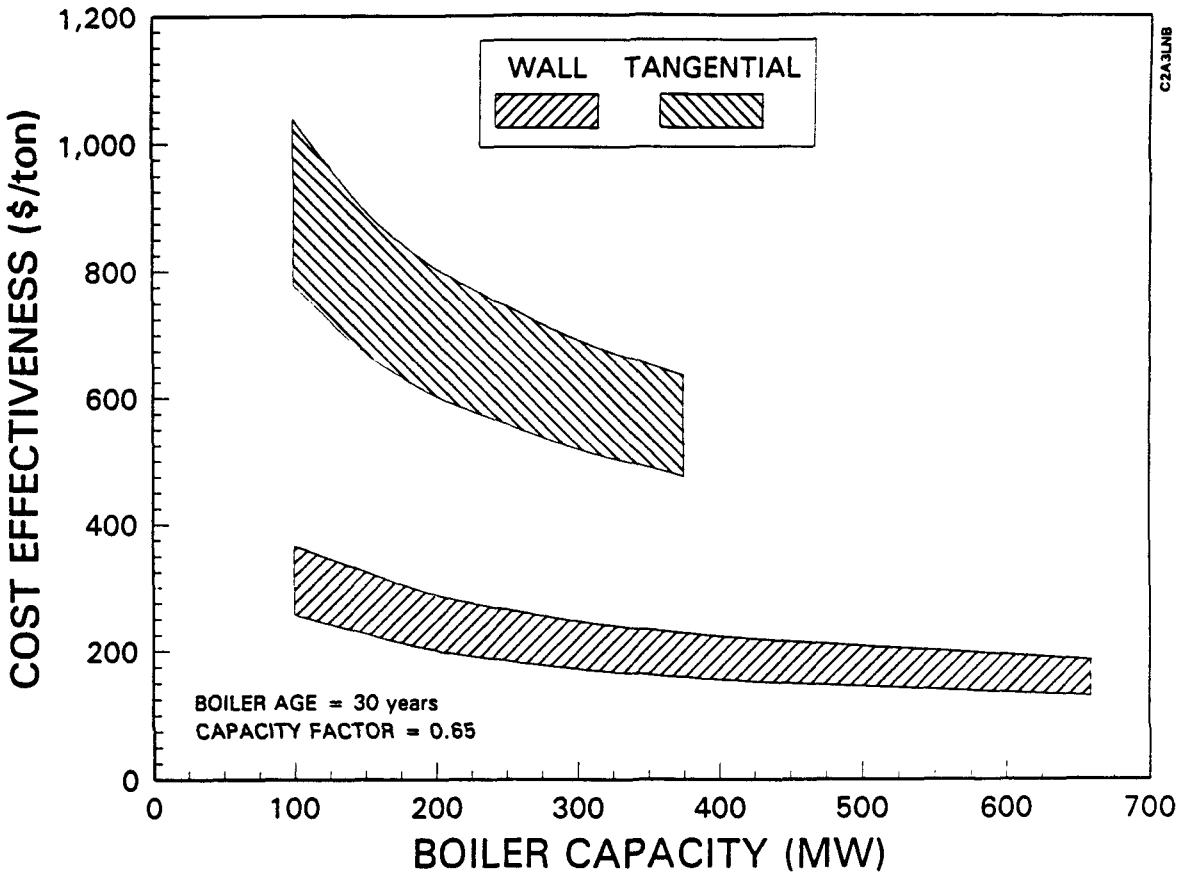


Figure 6-8. Cost effectiveness of LNB for wall and tangential PC-fired boilers

capacity. For wall-fired boilers, the cost effectiveness of LNB are lower than those calculated for OFA alone.

6.1.3 Low-NO_x Burners and Advanced Overfire Air (LNB+AOFA)

LNB+OFA, or AOFA, for wall-fired boilers and LNCFS Level II and III with SOFA are the most effective combination of combustion modification control techniques evaluated to date for PC-fired boilers. Recent retrofit results on both tangential- and wall-fired boilers have shown NO_x reductions of 30 to 60 percent (see Table 4-4), and NO_x levels as low as 0.30 lb/MMBtu for some tangential boilers. Actual NO_x levels will vary according to coal properties and design and operational constraints of the retrofit and the method of reporting and data averaging (e.g., short- or long-term) as discussed in Section 4. For the most part, these levels are reported with minimal operational impacts such as accumulation of furnace slag, changes in furnace exit gas temperature (FEGT), waterwall corrosion, boiler load turndown capability, and effects on precipitator performance. However, several severe design and operational problems have been experienced in some retrofits pointing to the additional development needed for this combination of technologies (Sorge, 1992; Wingard, 1992). Because OFA is used, some reduction in boiler efficiency is anticipated as illustrated in Figure 6-1 and discussed in Section 7. For these cost estimates, an efficiency loss of 0.5 percent was used to determine the fuel penalty of the LNB+OFA retrofit.

The base capital costs for this combination control technology were determined from recent estimates for Plant Hammond Unit 4, for wall-fired boilers, and from cost trend shown in Figure 6-5

for tangential boilers; As of this writing, the Hammond Unit 4 provided the only cost data for LNB+OFA for wall-fired units as shown in Figure 6-4. Figures 6-9 and 6-10 illustrate the TCR and busbar costs calculated for wall- and tangentially-fired PC boilers retrofitted with LNB+AOFA systems. In all cases, the retrofit included the complete replacement (for T-fired boilers) or extensive modification (for wall- or opposed-fired boilers) of the existing windbox, installation of AOFA air ducts and windbox, dampers and controls, and a new burner management system.

As shown in Figures 6-9 and 6-10, with the exception of the units smaller than 100 MWe, the cost of this retrofit technology on wall-fired boilers is estimated to range from slightly over $20/kW for the largest boilers (660 MWe for wall-firing and 375 MWe for T-firing) to more than $40/kW for the smaller boilers. In contrast, retrofit estimates in 1983 dollars for 140 MWe wall-fired boilers were as high as $17.8/kW (Lisauskas, 1987). For tangential boilers, the costs are estimated to be slightly less, depending on the number of burner corners to be modified (4 or 8).

Figure 6-11 illustrates the corresponding cost effectiveness estimates for the two retrofit cases. The band of costs for T-fired boilers is wider because of the larger range in control reduction effectiveness resulting from SOFA. It should also be emphasized that because T-fired boilers have an initial NO_x level lower than wall-fired boilers (i.e., the average uncontrolled NO_x in NESCAUM is 0.6 lb/MMBtu for T-firing and 0.95 lb/MMBtu for wall- and opposed-firing), equivalent capital and operating costs will result in higher costs per ton of NO_x removed for T-fired units. Therefore, for 30-year-old boilers with a 0.65 capacity factor, the estimated LNB+OFA cost effectiveness for wall-firing is between about $200/ton and $600/ton, compared to $400/ton to $1,200/ton for T-firing.

Boiler age and capacity factor influence the cost-effectiveness of these controls. Figures 6-12 and 6-13 illustrate the effect of boiler age and capacity factor on the cost effectiveness of the LNCFS II or III burner (for T-fired units) and LNB+OFA for wall-fired units retrofitted on 200-MWe boilers. The effect of boiler age is to increase the levelization factor for the TCR. Therefore, retrofits that have a high TCR will show a significant effect of boiler age which results in increased cost. The effect of lower book life is to increase cost effectiveness by about 20 percent. Similarly, lower capacity factors increase overall costs, as shown in Figure 6-13. These estimates suggest that to reduce 1 ton of NO_x from a boiler operating with a 40 percent capacity factor instead of 65 percent will cost approximately 50 percent more. However, it is apparent that the amount of NO_x reduction is the principal variable affecting cost effectiveness.

6.1.4 Reburn for Cyclone Boilers

The cost of NGR is sensitive to three principal factors: the availability of onsite natural gas pipeline, the cost of natural gas compared to the coal, and the amount of reburning used (Farzan, 1989 and Maringo, 1987). In Section 4, NGR is considered for application to all major boiler types. However, a cost analysis was presented only for cyclone boilers because these retrofits will provide the most attractive cost effectiveness for this technology due to the larger NO_x reductions that can be achieved. Cost analyses for NGR retrofit on wall and tangential units are presented in Appendix F. The cost for wet-bottom boilers will be influenced by the size of the furnace and the available residence time to induce an effective reburn and complete combustion within the available furnace volume. Research by B&W indicates that NGR can be applied to most cyclone boilers without negative effects on the heat absorption profile in the furnace. An increase in efficiency loss is anticipated, however (Farzan, 1989; EERC, 1990). A recent report by the developer, Energy and Environmental Research Corporation (EERC) for GRI sets the capital cost at $30/kW for large capacity boilers (EERC, 1990). The report also states that there are no adverse operational impacts of gas reburning. Several demonstrations to evaluate these claims are ongoing.

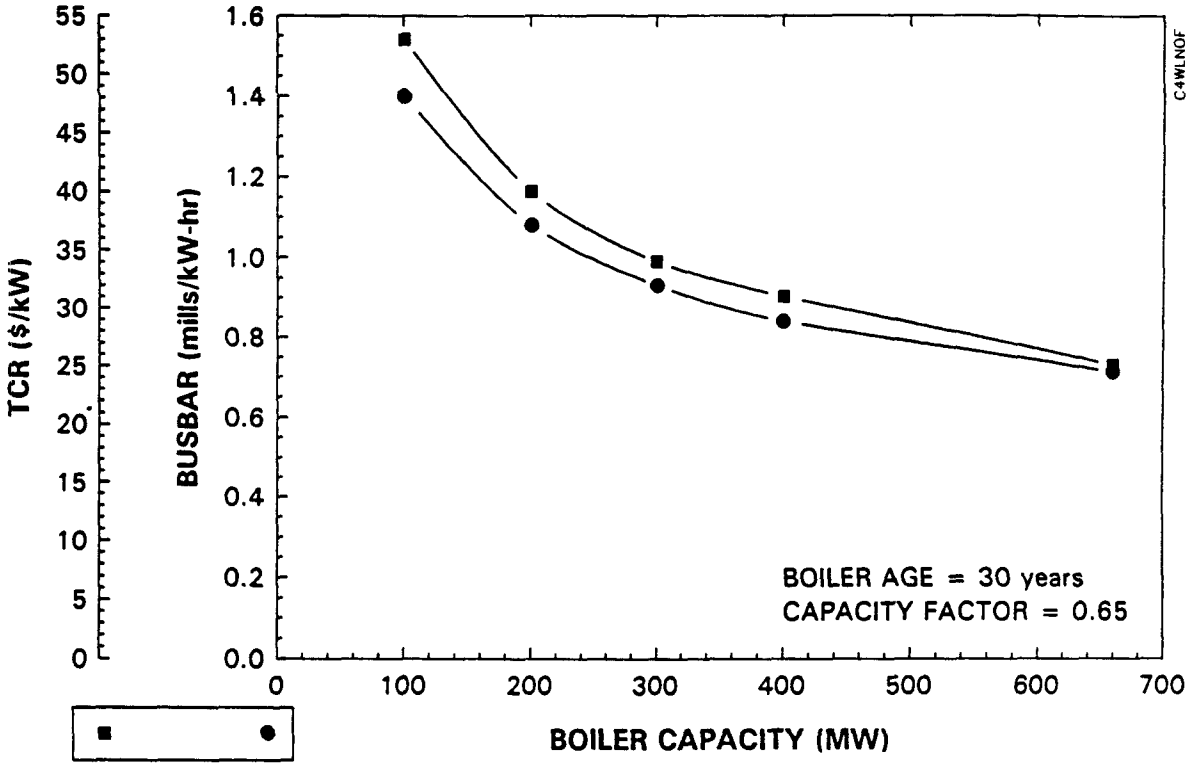


Figure 6-9. Capital and busbar cost of LNB+OFA retrofit for wall-fired PC boilers

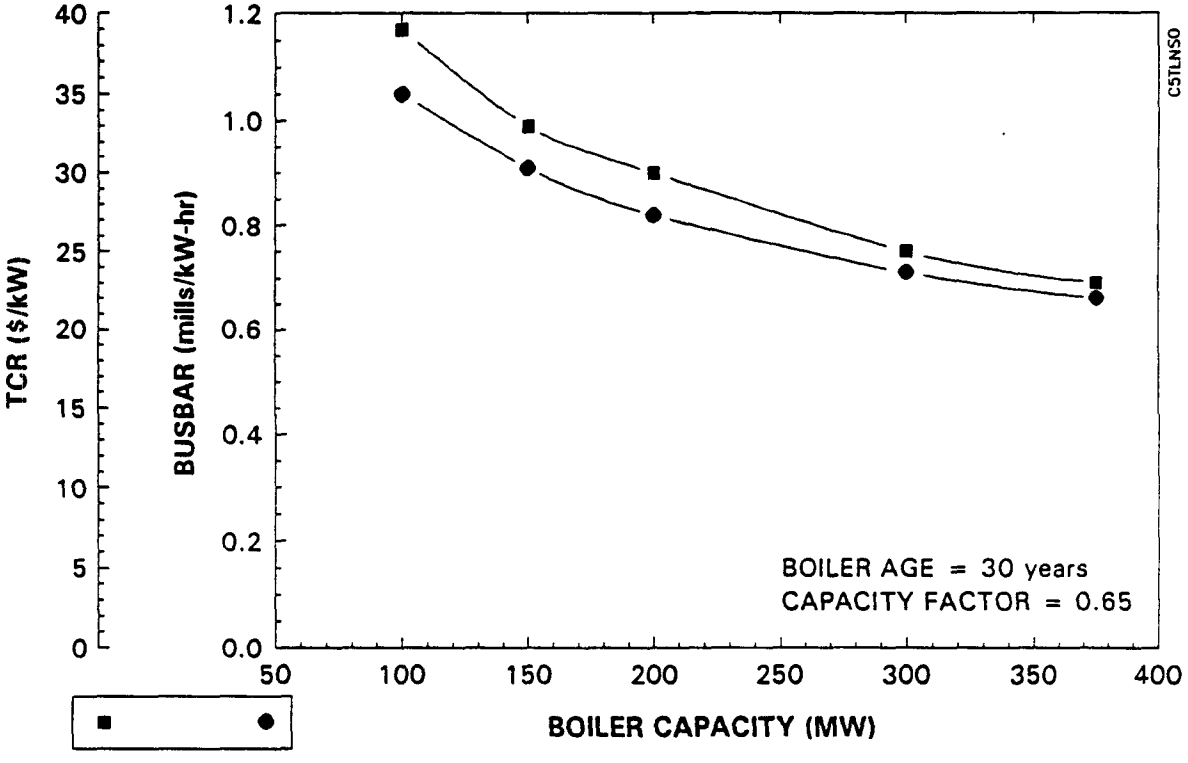


Figure 6-10. Capital and busbar cost of LNB+SOFA retrofit for tangential-fired PC boilers

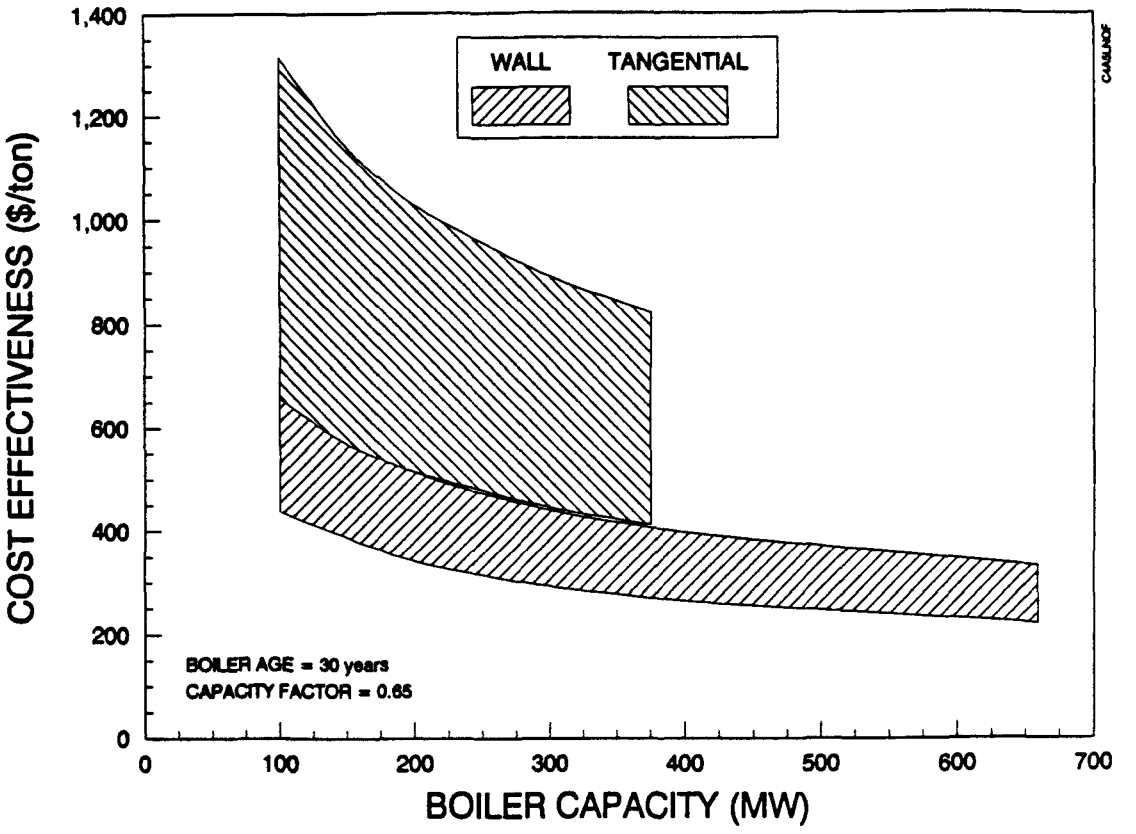


Figure 6-11. Cost effectiveness of LNB + OFA retrofit for wall and tangential PC-fired boilers

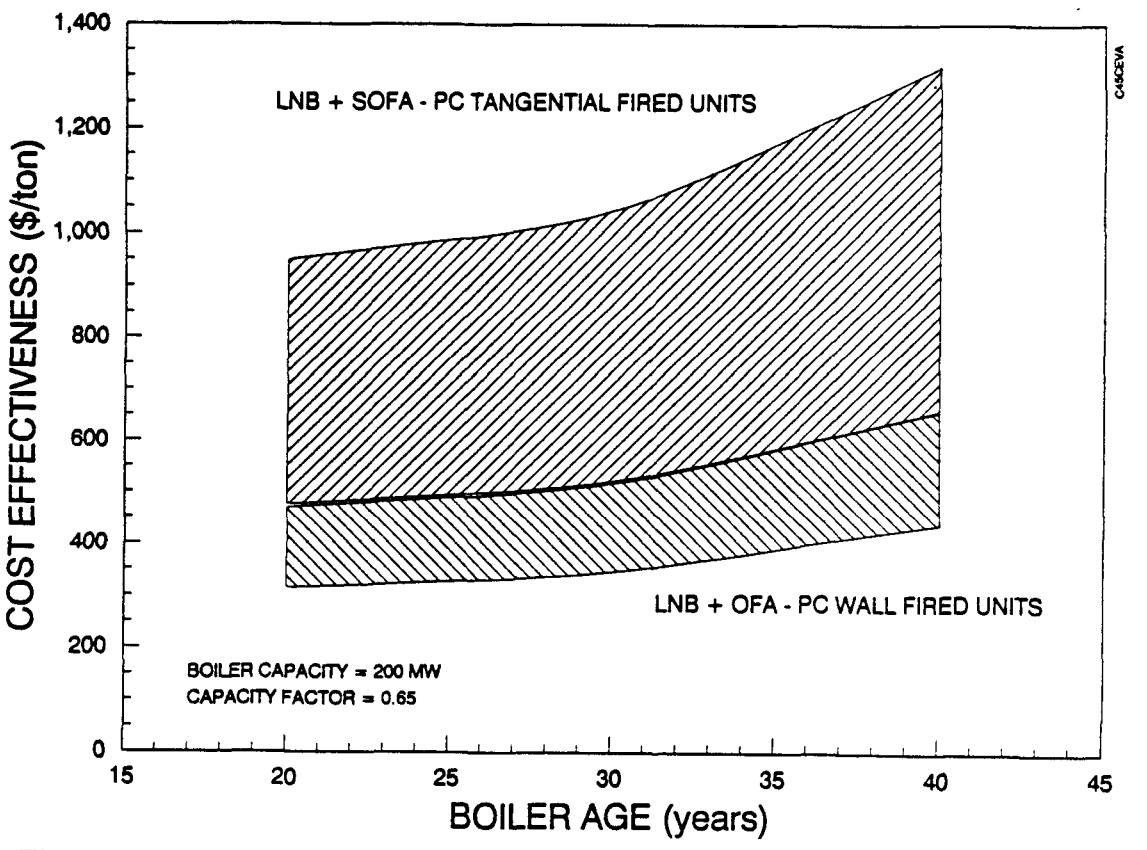


Figure 6-12. Effect of boiler age on the cost effectiveness of LNB + OFA systems

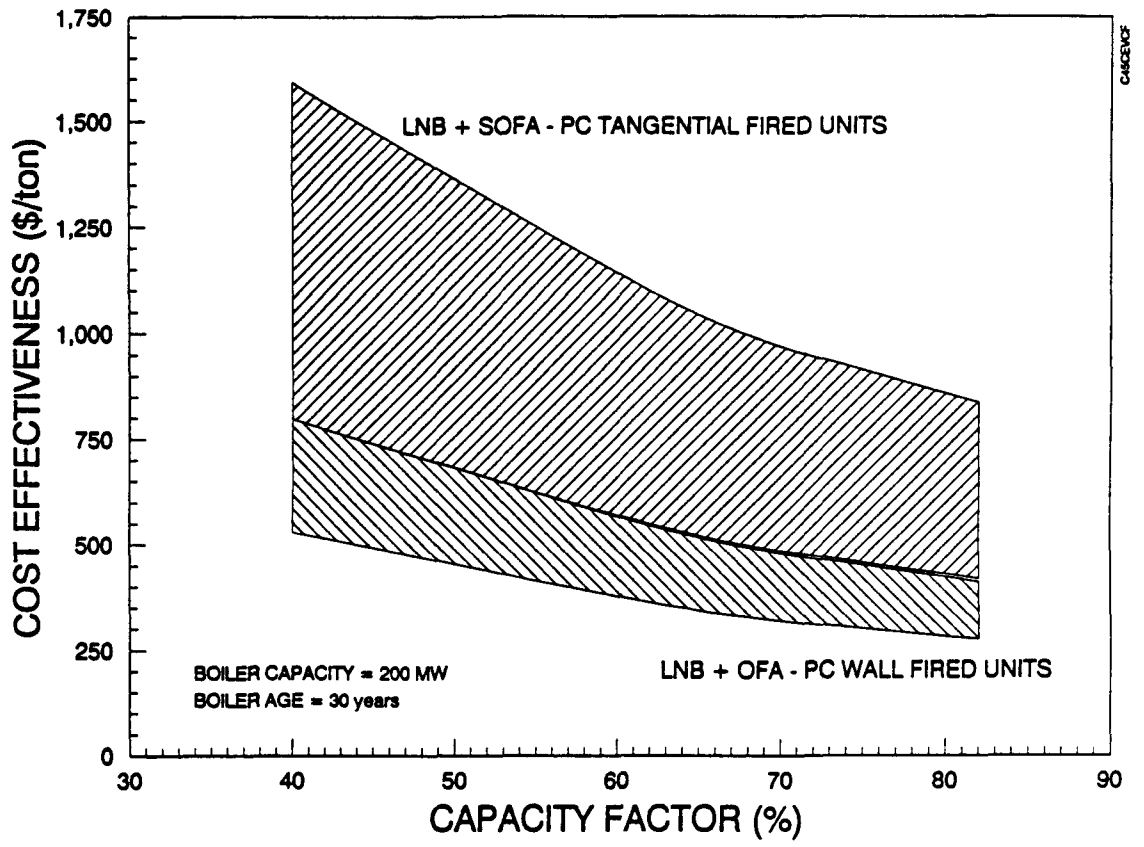


Figure 6-13. Effect of capacity factor on the cost effectiveness of LNB + OFA systems

NGR costs were developed using the capital equipment cost reported for a 200-MWe cyclone with 50-percent NO_x reduction and with a natural gas use rate of 15 percent of the total heat input (Farzan, 1989). In that study, the process capital cost was estimated at $22.4/kW for a 200-MWe cyclone boiler and the busbar rate at 2.3 mills/kWh. Thermal efficiency loss of 0.5 percent was assumed to account for additional latent heat of increased moisture in the flue gas. When installing a gas pipeline or using coal as the reburning fuel, the capital cost is reported to double to the range of $41 to $44/kW. Estimates for pipeline installation are about $1M/mi. This pipeline cost was not considered in the analysis because of wide variability in cost. The levelized busbar cost increases to $3.1 mills/kWh in the case of the pipeline requirement. Fuel differential cost savings reduce the busbar cost for coal reburning to less than that of NGR (Farzan, 1989).

Figures 6-14 and 6-15 illustrate the costs calculated for the NESCAUM study using the Farzan process capital cost data and EPRI economic premises. The data indicate a TCR in the range of $35 to $50/kW scaled according to boiler size and a cost effectiveness in the range of about $500 to $800/ton for a NO_x reduction of 45 to 65 percent from an uncontrolled NO_x level of 1.28 lb/MMBtu. Because of the large contribution of fuel cost to the total busbar cost, the cost effectiveness was found not to vary appreciably with capacity factor or age of the boiler. The cost effectiveness of NGR is heavily influenced by the differential in cost between natural gas and coal as shown in Figure 6-16. These cost estimates do not include an economic credit for the reduction of SO_2 emissions. SO_2 emissions are reduced by an amount equivalent to the coal displaced. This credit can be an important consideration if the retrofit boiler is also subjected to SO_2 control. This credit is estimated by GRI at $500 to $700/ton (EERC, 1991).

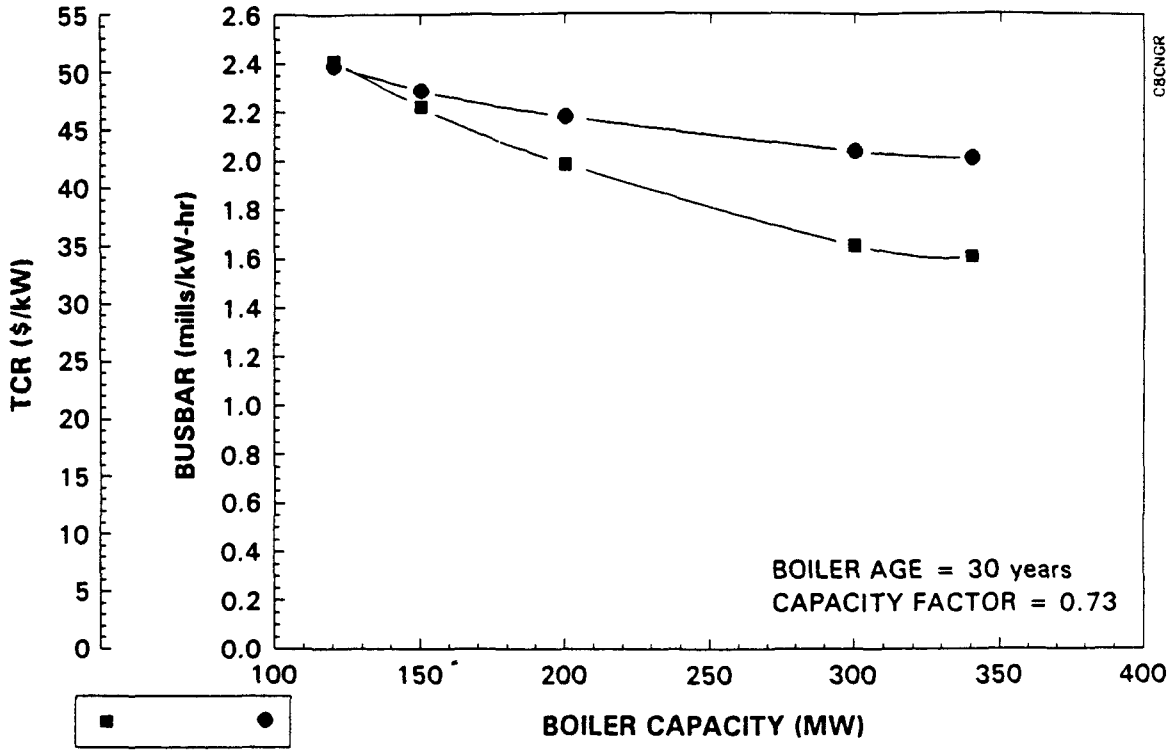


Figure 6-14. Capital and busbar cost of NGR for cyclone boilers

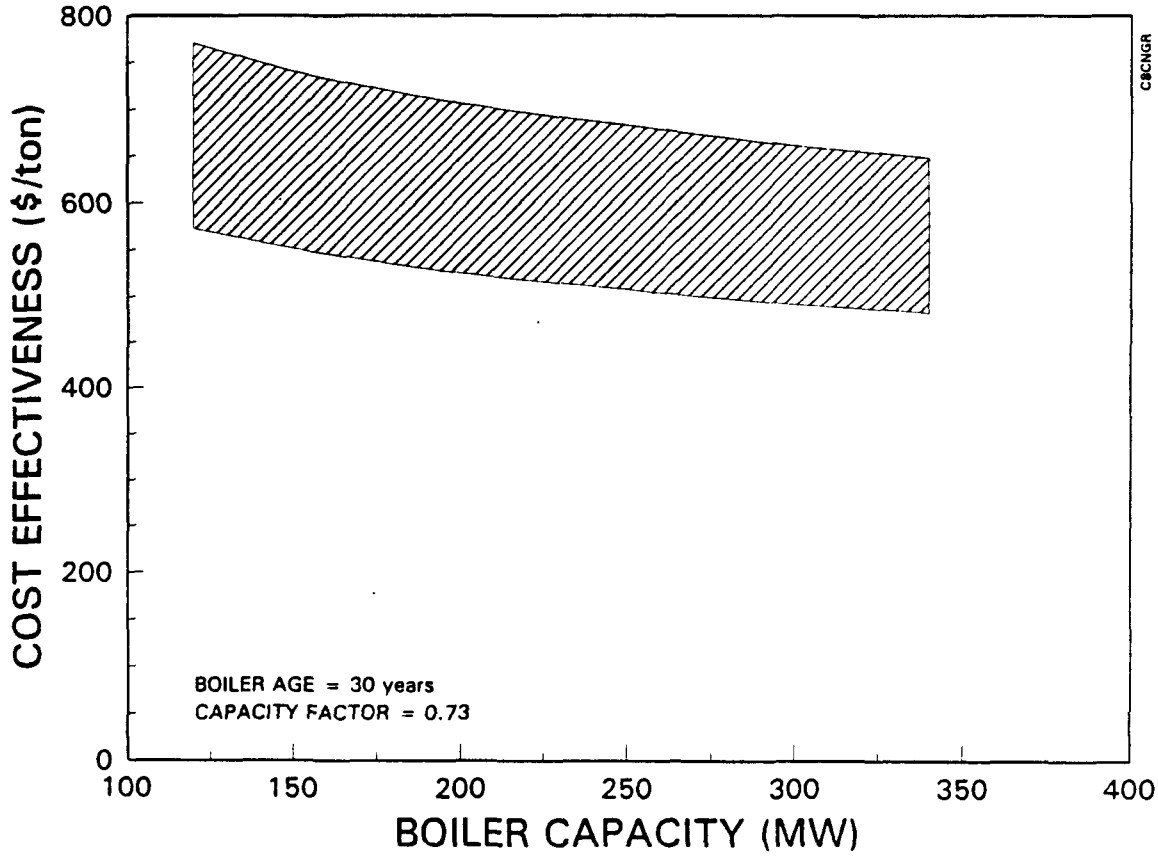


Figure 6-15. Cost effectiveness of NGR for cyclone boilers

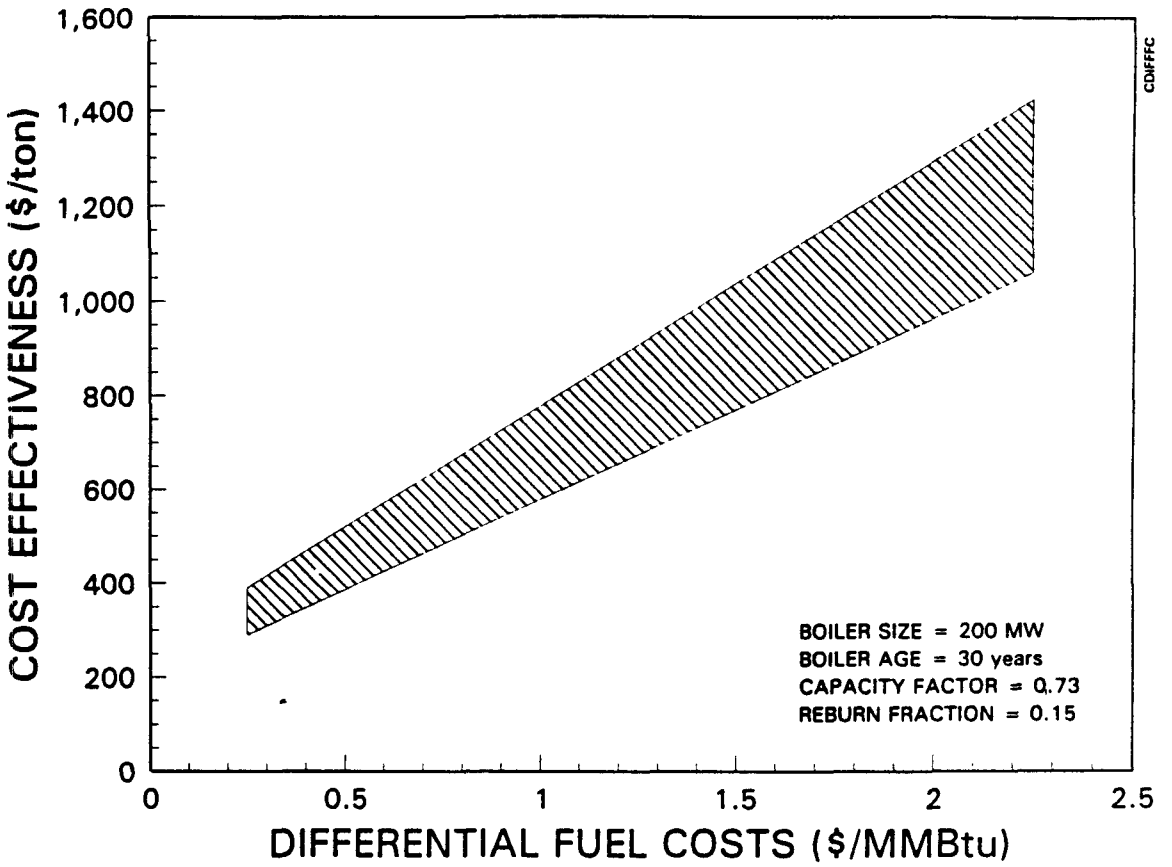


Figure 6-16. Effect of fuel differential cost on the cost effectiveness of NGR for cyclone boilers

6.1.5 Summary of Combustion Modification Retrofit Costs for Coal-Burning Power Plants

Table 6-4 summarizes the costs calculated for several retrofits of coal-fired boilers with combustion modifications. These costs are for a 20- to 40-year-old 200-MWe boiler with a capacity factor in the range of 40 to 82 percent. The data illustrate that the cost effectiveness of these combustion modification controls ranges between $160 and $1,200/ton of NO_x removed, for wall-fired boilers, and $420 to $2,200/ton, for tangential units. The actual cost is based on several factors not limited to boiler capacity, baseline NO_x, boiler age, and capacity factor. The cost to reduce emission levels with LNB only for tangential boilers and for wall-fired boilers is estimated to be lower than all other options, including OFA only, LNB+OFA, and reburn.

6.2 CONTROLS FOR OIL-/GAS-FIRED BOILERS

Combustion modification NO_x control technologies for oil-/gas-fired boiler retrofits evaluated for cost in this study include:

- Burners out of service (BOOS)
- Flue gas recirculation (FGR)
- Low-NO_x burners (LNB)
- BOOS+FGR
- LNB+OFA+FGR

Table 6-4. Summary of NO_x combustion control costs for coal-fired utility boilers (1st Qtr $1991)

Boiler Firing Type	NO_x Control Technology	Uncontrolled NO_x Level[a] (lb/MMBtu)	Estimated Range in NO_x Control Levels[b] (lb/MMBtu)	Control Costs		
				Total Capital Requirement ($/kW)	Levelized Busbar (Mills/kWh)	Cost Effectiveness ($/ton)
Wall-firing	OFA	0.95	0.70 - 0.80	20	0.49 - 0.75	410 - 1,100
	LNB	0.95	0.45 - 0.60	20	0.43 - 0.69	160 - 450
	LNB+OFA	0.95	0.35 - 0.55	40	0.88 - 1.7	270 - 800
	NGR	0.95	0.40 - 0.50	42	2.1 - 2.9	710 - 1,200
Tangential-firing	LNB w/CCOFA	0.60	0.40 - 0.45	24	0.52 - 1.0	490 - 1,270
	LNB+SOFA	0.60	0.30 - 0.45	30	0.67 - 1.3	420 - 1,590
	NGR	0.60	0.25 - 0.35	42	2.1 - 2.9	1,110 - 2,180
Cyclones	NGR	1.28	0.50 - 0.70	42	2.1 - 2.5	500 - 800

These costs were developed for the following conditions:
200 MWe for all boilers. (See Section 6 for effect of capacity on these costs)
Capacity factors = 40 to 82 percent for wall and tangential units, 55 to 83 percent for cyclones
Boiler age 20 to 40 years for wall and tangential units, 27 years for cyclones

[a]See Table 3-4 for average baseline levels in the NESCAUM Region. Only pre-NSPS units are considered.
[b]See Tables 1-1 and 1-3, Section 4 and Appendix D for estimated range in controlled NO_x levels.

Reburning was not considered for these boilers because the retrofit experience with this approach is minimal. Ongoing research in Italy, and, to some extent, in the United States, has shown that NGR for oil-fired boilers can offer NO_x reduction potentials on the same order as those attainable with more conventional controls. Therefore, it holds promise for some applications. No cost data are available, however.

The following section discuss the costs developed in this study. For each of these technologies, capital and operating cost information reported in the literature was used to establish the base case on which the EPRI economic premises were applied. Standard procedures were then applied to develop costing for various boiler applications according to capacities, age, and capacity factor. Appendix G provides details of cost calculations for these boiler retrofit test cases.

6.2.1 Burners Out Of Service (BOOS)

The basic cost information for this technology was taken from a recent study for the Empire State Electric Energy Research Corporation (Mormile, 1990). BOOS is the simplest and least expensive combustion modification for oil-/gas-fired utility boilers. Its implementation requires no retrofit equipment with the exception of some online analyzer for emissions monitoring. The principal capital cost is due to the combustion and emissions testing that is necessary to select the optimum burner pattern for minimum NO_x, with the least impact on emissions of other pollutants, efficiency loss, and operational impacts such as load turndown capabilities. The impact on the boilers is difficult to ascertain because it can vary significantly with the boiler burner pattern and the steam load requirements of the unit. Loss in boiler efficiency can vary between zero and 1 percent depending on the degree of staging applied and the resulting increase in the minimum excess oxygen necessary to ensure good combustion. An efficiency loss of 0.3 percent was used based on estimates provided by Consolidated Edison and past NO_x control efforts (Hunter, 1989). BOOS is applicable to both wall-fired (single wall or opposed) and T-fired boilers.

Figures 6-17 and 6-18 illustrates the cost and cost effectiveness of BOOS as a function of boiler capacity. The TCR is estimated at less than $1.0/kW for most size units and the cost effectiveness is estimated to be relatively independent of boiler capacity at less than $200/ton. The cost effectiveness for wall-fired boilers, which is based on a reduction from an average of 0.45 lb/MMBtu to a range of 0.30 to 0.35 lb/MMBtu (20 to 35 percent efficiency) for most units, does not vary significantly with boiler size because most of the cost is due to loss of fuel efficiency. Higher NO_x reductions and thus improved cost effectiveness, are possible for boilers with initially high baseline levels. Therefore, higher costs are anticipated for BOOS on T-fired boilers.

6.2.2 Flue Gas Recirculation (FGR)

The retrofit installation of WFGR can be quite costly. The fan, flues, dampers and controls, as well as possibly requiring existing fan capacity to be increased due to increased draft loss, can represent a large investment. The amount of WFGR is generally maintained at levels lower than 25 percent because of draft loss, cost, and flame instability. Little additional NO_x reduction is gained with FGR rates greater than 15 percent. In addition, the FGR system can require a substantial maintenance program.

Costs for FGR were also developed based on capital and O&M costs published under the ESEERCO study (Mormile, 1990, and Hunter, 1989). FGR is applicable to both tangential and wall-fired boilers. The retrofit of FGR requires the installation of a fan to recirculate up to 30 percent of the flue gas to the windbox, ducting, and associated dampers and controls. Detailed combustion testing is also necessary to ensure adequate distribution of the FGR flow to each burner

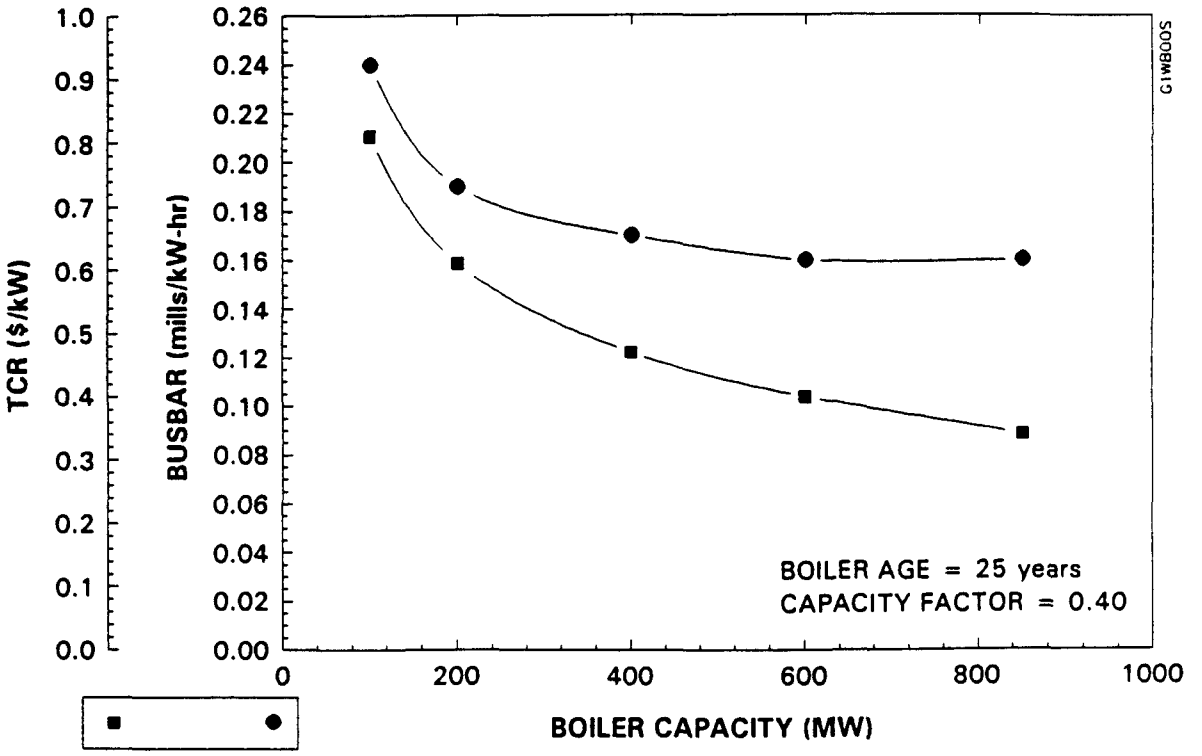


Figure 6-17. Capital and busbar cost of BOOS for oil/gas wall-fired boilers

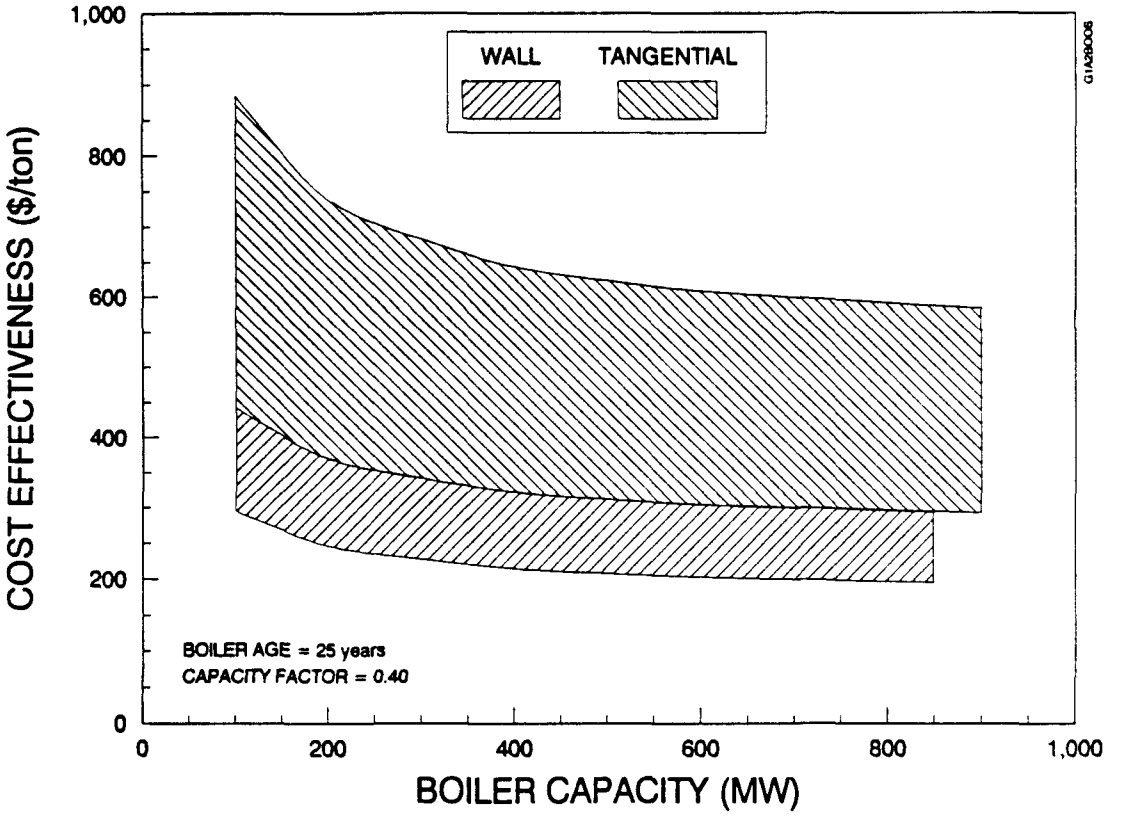


Figure 6-18. Cost effectiveness of BOOS for wall and tangential oil-/gas-fired boilers

and to determine the most effective FGR rates through the boiler load range. Figures 6-19 and 6-20 illustrate the calculated costs for FGR. TCR estimates range between $6/kW and $12/kW for units below 200 MWe; when the capacity factor is more than 0.40, the cost effectiveness for units 200 MWe and larger ranges from about $300 to $1,000 per ton of NO_x removed for wall-firing, twice as much for T-firing. The NO_x reduction effectiveness of FGR and, consequently the cost effectiveness, very significantly with the type of boiler fuel. Better FGR performance and lower cost should be anticipated when burning clean fuels such as natural gas and high-grade fuel oil.

6.2.3 Low-NO_x Burners (LNB)

As discussed in Section 4, LNB for oil- and gas-fired utility boilers has only recently been introduced as a retrofit option. The intent of these retrofits, especially in California, has been primarily to improve combustion stability at extremely low NO_x conditions induced by other controls such as FGR, OFA, BOOS, or a combination of these.

Estimates of LNB retrofit cost for this study were based primarily on estimates provided by Consolidated Edison Co. (Mormile 1989). These utility estimates show a cost of $20/kW for a 350 MWe boiler. In comparison, the retrofit of B&Ws PG-DRB burners on LADWP Haynes 230 MWe Unit 3 was reported to cost about $10/kW with additional $16/kW for asbestos removal and disposal, compartmenting the windbox, and adding a primary gas injection system (Carnevale, 1989). The Southern California experience shows that the estimate by Consolidated Edison in reasonable, and therefore it was adopted for this study.

Figures 6-21 and 6-22 illustrate the capital cost for retrofit of LNB on wall-fired boilers and cost effectiveness of this control option for wall and tangential units. These estimates show that LNB will cost from about $16 to 38/kW to retrofit depending on the size of the boiler. The cost to removal 1 ton of NO_x will be higher for a 200 MWe tangential unit ($1,000 to $5,000/ton) than for a wall-fired unit ($750 to $1,700/ton) because of higher NO_x reductions anticipated for wall-fired boilers.

6.2.4 Burners Out of Service and Flue Gas Recirculation (BOOS+FGR)

The combination of BOOS+FGR is an effective approach in the control of NO_x from oil-/gas-fired boilers. In place of BOOS, OFA ports can also be used to achieve the combustion staging necessary for deep reduction in NO_x or to provide better combustion air mixing. Appendix C provides schematics of retrofits of FGR and FGR+OFA techniques installed on Southern California boilers.

The basis for costing the BOOS+FGR combination of controls was simply derived from the addition of the individual costs discussed in Section 6.2.1 and 6.2.2. Figure 6-23 illustrates the capital cost of BOOS+FGR on a wall-fired boiler. The capital cost for a tangential boiler is anticipated to be the same. Figure 6-24 illustrates that the cost effectiveness of this control option can be quite low, from $440 to $850/ton for wall-firing and $580 to $1,300/ton for T-firing.

6.2.5 Low-NO_x Burners, Overfire air, and Flue Gas Recirculation (LNB+OFA+FGR)

Combining combustion controls provides for greater NO_x reduction potential. Although the costs are nearly additive, NO_x reductions are generally not. Cost data for two boiler retrofits with a combination of LNB+OFA+FGR have been reported (Bisonett, 1991; Yee, 1989; and Carnevale, 1989). The LNB was the B&W PG-DRB, which is designed to use FGR in combination with OFA.

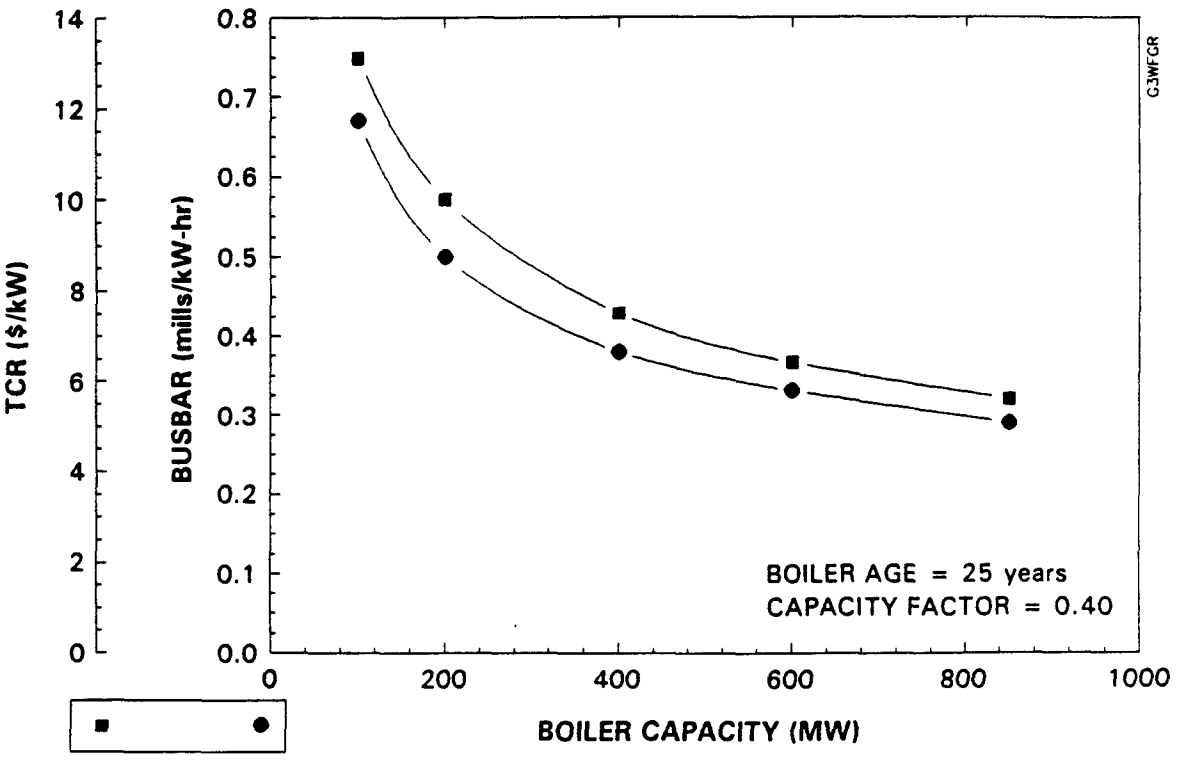


Figure 6-19. Capital and busbar cost of FGR for oil-/gas-fired boilers

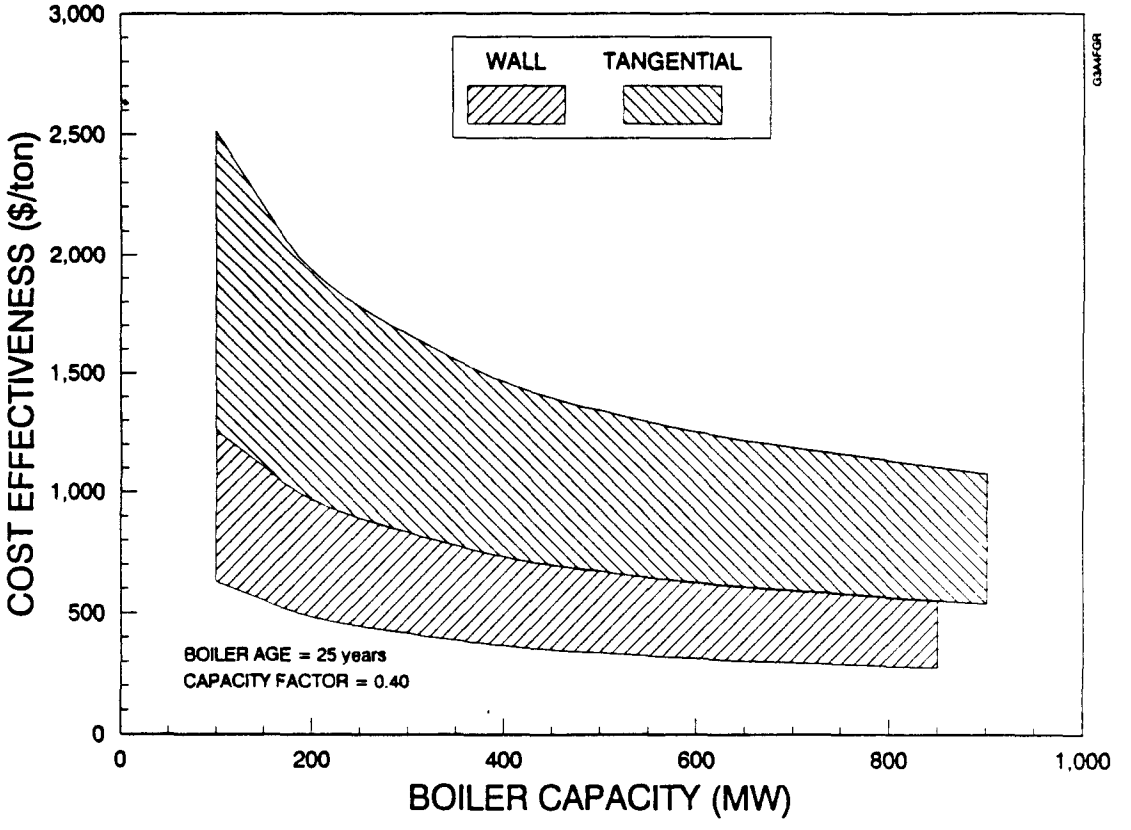


Figure 6-20. Cost effectiveness of FGR for wall and tangential oil-/gas-fired boilers

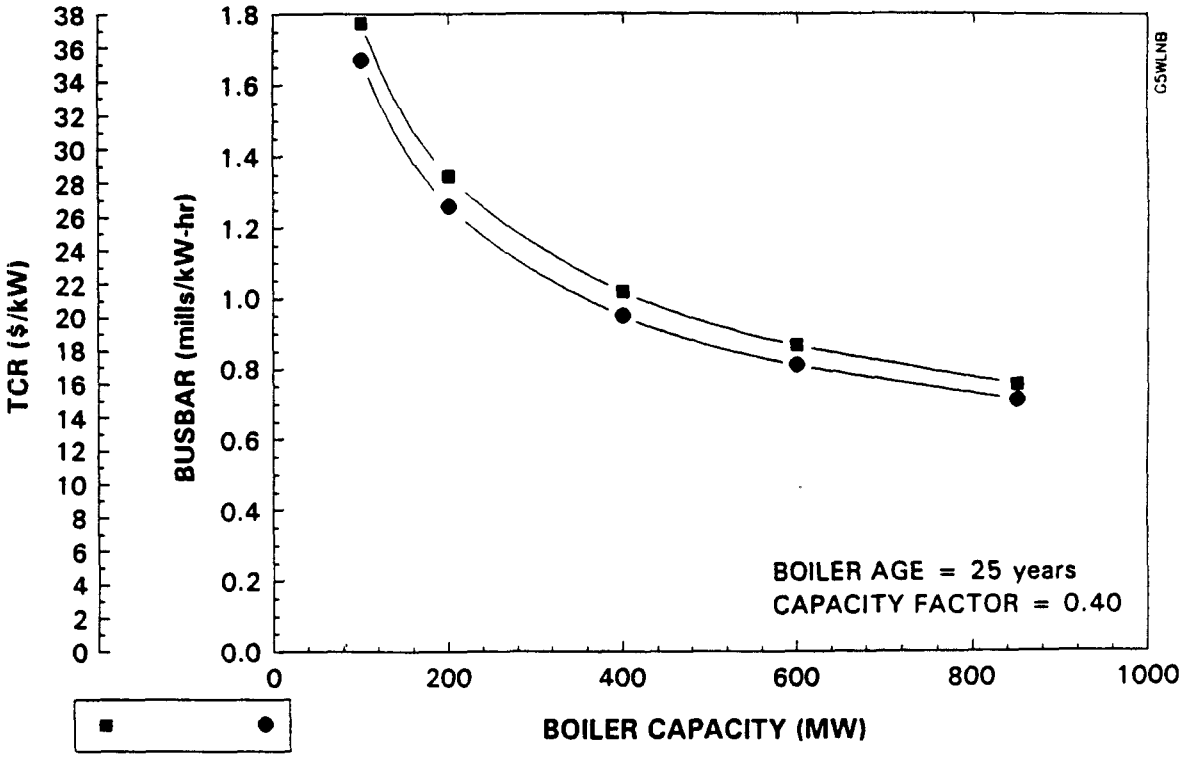


Figure 6-21. Capital and busbar cost of LNB for oil-/gas-fired boilers

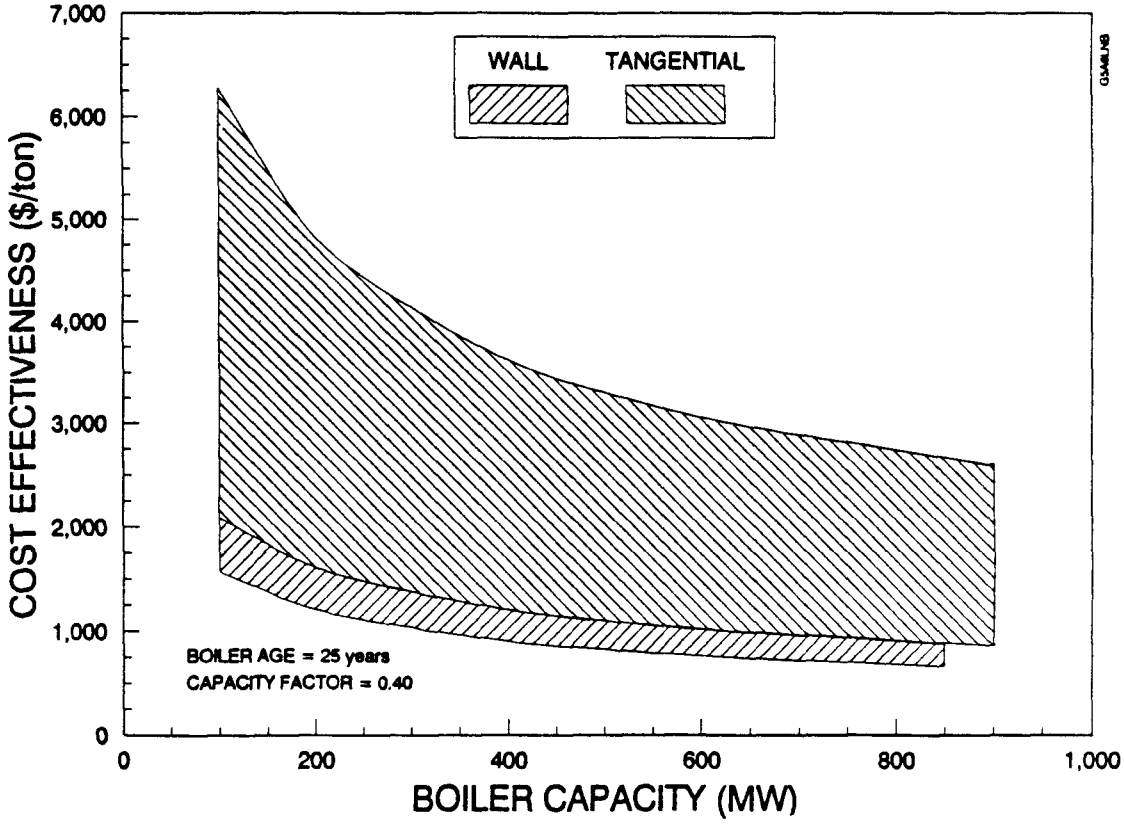


Figure 6-22. Cost effectiveness of LNB for wall and tangential oil-/gas-fired boilers

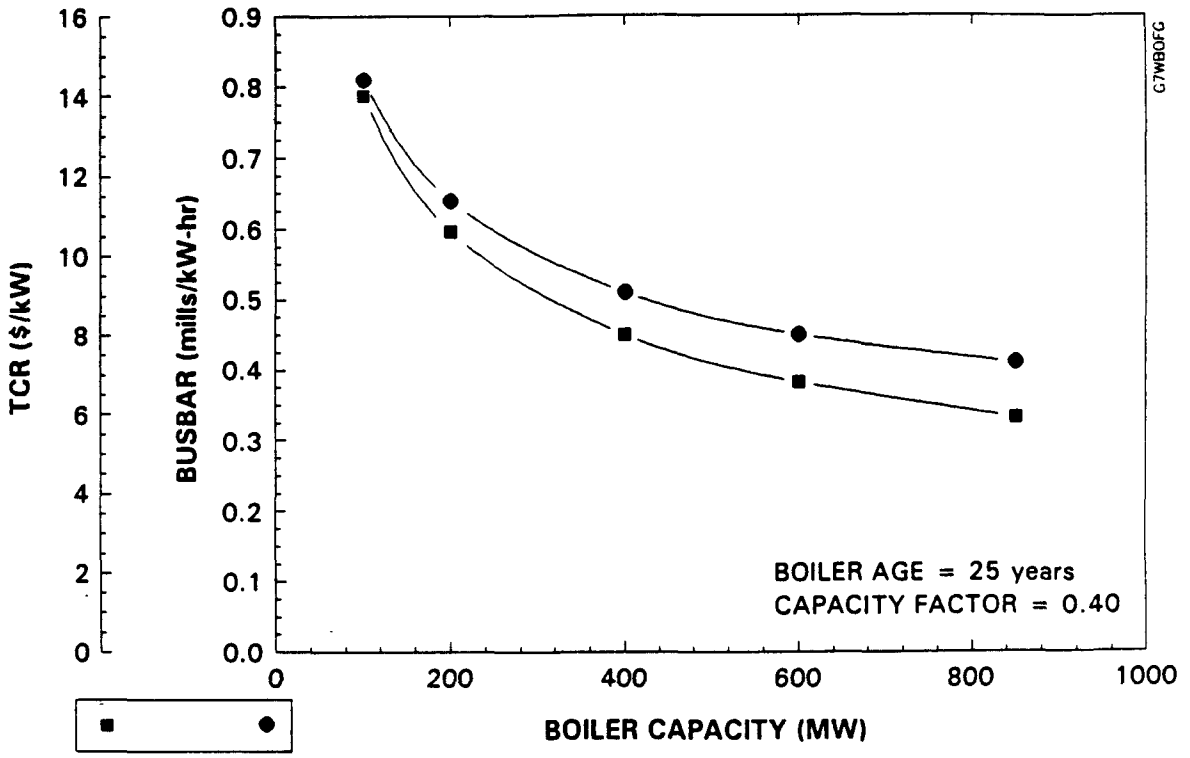


Figure 6-23. Capital and busbar cost of BOOS+FGR for oil-/gas-fired boilers

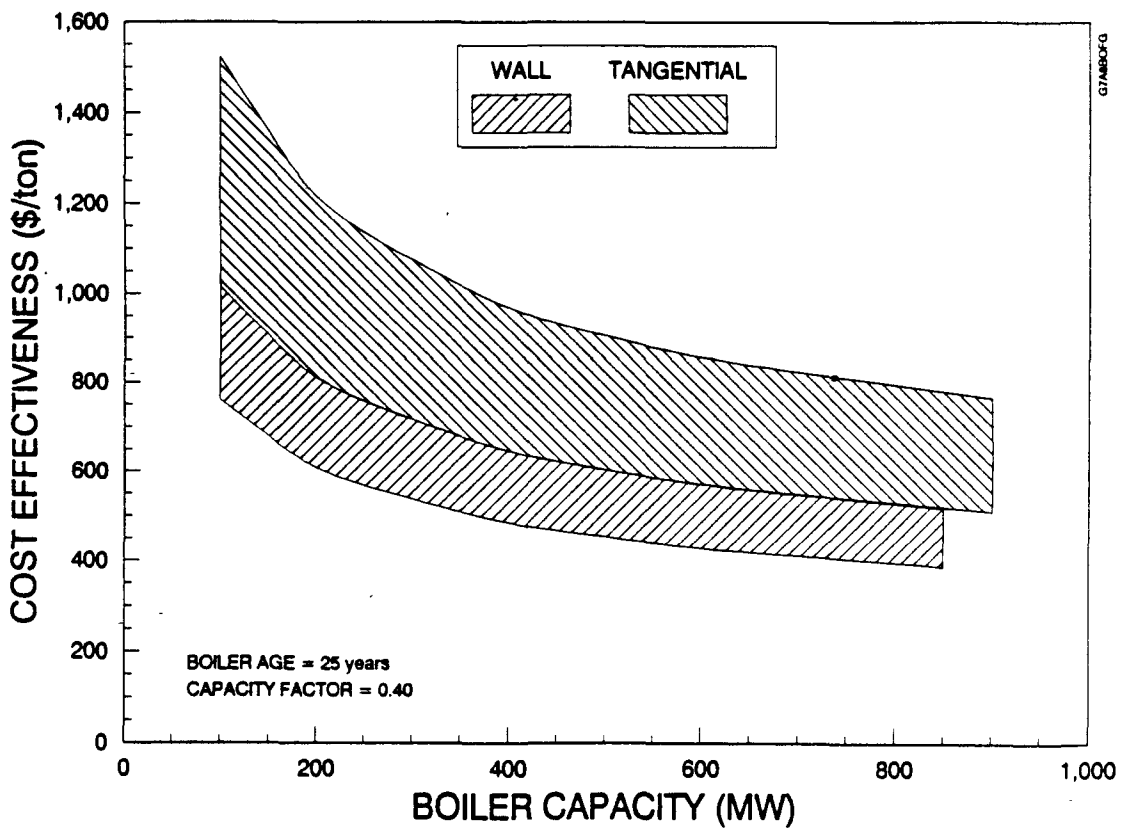


Figure 6-24. Cost effectiveness of BOOS+FGR for wall and tangential oil-/gas-fired boilers

This combination technology represents one of the most effective methods for reducing NO_x from oil-/gas-fired boilers.

Engineering evaluation of the retrofit modifications to an opposed-fired 345-MWe boiler, owned and operated by PG&E, show that the modifications required to achieve a reduction in NO_x from the 350 to 400 ppm (0.45 to 0.51 lb/MMBtu) to 75 to 150 ppm (0.10 to 0.20 lb/MMBtu) range included the following (Bisonett, 1991):

- Replace FGR fan motor
- Install new FGR and OFA ducts and dampers
- Install 24 new PG-DRB burners and associated piping and controls
- Partial replacement of superheater tube banks
- Upgrade of steam attemperation for increased capacity
- Installation of 12 OFA ports
- Upgrade of boiler control system

The reported TCR for this installation was $45.7/kW with a total levelized cost of 3.7 mills/kWh.

The second cost estimate for a similar retrofit application, but this time on a 145-MWe front wall-fired boiler. The equipment modification implemented on this unit included (Yee, 1989):

- Installation of nine PG-DRB B&W LNBs and OFA ports
- Improved steam atomizers for oil firing
- Upgrading of the boiler control system
- Modification of the existing FGR system

As indicated, the boiler was already equipped with FGR and required only modifications and upgrades to meet the requirement of the PG-DRB operation. The reported TCR for this retrofit installation cost was $26/kW. Because the unit was already equipped with FGR, this cost was avoided in the retrofit. NO_x emissions were reduced significantly from this boiler from about 600 ppm (0.75 lb/MMBtu) without any controls burning oil to a guaranteed level of 180 ppm (0.23 lb/MMBtu).

The third retrofit cost of this most-effective combustion control combination was reported by the Los Angeles Department of Water and Power (Carnevale, 1989). For this retrofit, the 230-MWe opposed-fired Haynes Unit 3 was selected for the economic evaluation. The PG-DRB burners with a combination of OFA and FGR required the following modification to the boiler and ancillary equipment (Carnevale, 1989):

- Replacement of the existing mechanical atomized circular oil/gas burners with steam-atomized PG-DRB with 20 percent FGR capability

- Modification of the existing windbox using compartmentalization for better air flow distribution. (also required asbestos removal)

- Installation of OFA ports and associated ducting, dampers, and controls

- Replacement of the existing FGR fans and associated ductwork, dampers, and controls

- Improved boiler management system

- Significant structural modifications to accommodate the new ducting arrangement

The total retrofit cost of this equipment was estimated at $51/kW.

These three retrofit cases provide a range in costs for the same technology based on the use of the B&W PG-DRB burner patterned after the Babcock Hitachi K.K. (BHK) HTNR design. These costs range from $26/kW, for the 145-MWe boiler, to $51/kW, for the 230-MWe LADWP retrofit case. The low estimate, however, does not include the installation of a new FGR system, necessary for a facility not already equipped with this low-NO_x technology. For our cost analysis, we based the calculations of the retrofit cost on the TCR estimates provided by LADWP (Carnevale, 1989).

Figure 6-25 illustrates the calculated costs for this control option for oil/gas wall-fired boilers. The TCR ranged from about $34/kW to $72/kW for boilers in the 100 to 850 MWe range (the NESCAUM boiler range). The cost for smaller units escalates significantly. For 200-MWe boilers with a capacity factor greater than 0.40, the cost effectiveness for wall-fired boilers ranges from about $1,400 to $2,500 for the older and smaller boilers, as shown in Figure 6-26.

6.2.6 Summary of Combustion Modification Retrofit Costs for Oil- and Gas-Fired Power Plants

Table 6-5 summarizes the costs for combustion controls on oil- and gas-fired boilers with a medium capacity of 200 MWe. Minimum NO_x levels for these units are estimated to be on the order of 0.10 to 0.20 lb/MMBtu deemed more likely when burning clean fuels with little or no nitrogen content. This control level corresponds to a reduction of about 45 to 80 percent for wall-fired boilers and about 40 to 60 percent for T-fired units. The costs of these reductions are estimated to range between $900/ton and $2,000/ton, for controls on wall-fired boilers, and $1,600/ton to $5,200/ton, for controls on tangential boilers, based on a combination of OFA, LNB, and FGR. Larger capacity boilers would exhibit lower costs. NO_x reduction on the order of 15 to 40 percent can be achieved on some boilers at very low cost using BOOS.

6.3 FLUE GAS TREATMENT CONTROLS

Flue gas treatment controls evaluated for the cost of retrofit on oil-/gas- fired and coal-fired boilers include the urea-based SNCR and the ammonia-based SCR processes. For PC-fired power plants, the SCR cost was based on the retrofit of the reactor downstream of any particulate or SO_2 control systems (cold-side). Although more costly than the hot-side SCR installations more commonly found in Europe and Japan, the cold-side retrofit application is considered more feasible for United States coals (Lowe, 1991). This application requires the expensive use of fuel to reheat the flue gas to catalytic reaction temperatures. SCR capital and cost data for oil-/gas-fired boilers used in this cost analysis were taken from the information obtained by SCE (Johnson, 1991). For PC-fired power plants, the capital and operating cost data were reported in a detailed study sponsored by EPRI (Robie, 1990). Economic data for SNCR capital cost were supplied by vendors of the technology and in recent full-scale retrofits (Albanese, 1991; Johnson, 1991; Hunt, 1992; and Teixeira, 1992).

Tables 6-6 and 6-7 summarize the range in costs for these FGT technologies when retrofitted to coal- and oil-/gas-fired boilers, respectively. Cost effectiveness values are reported for two types of applications: (a) boilers with uncontrolled NO_x emissions, and (b) boilers whose emissions have been lowered with available controls such as LNB for PC units and TSC (BOOS or OFA)+FGR for oil-/gas-fired units. NO_x levels controlled with a combination of commercially available combustion modifications coupled with SCR range between 0.05 to 0.10 lb/MMBtu, for oil-/gas-

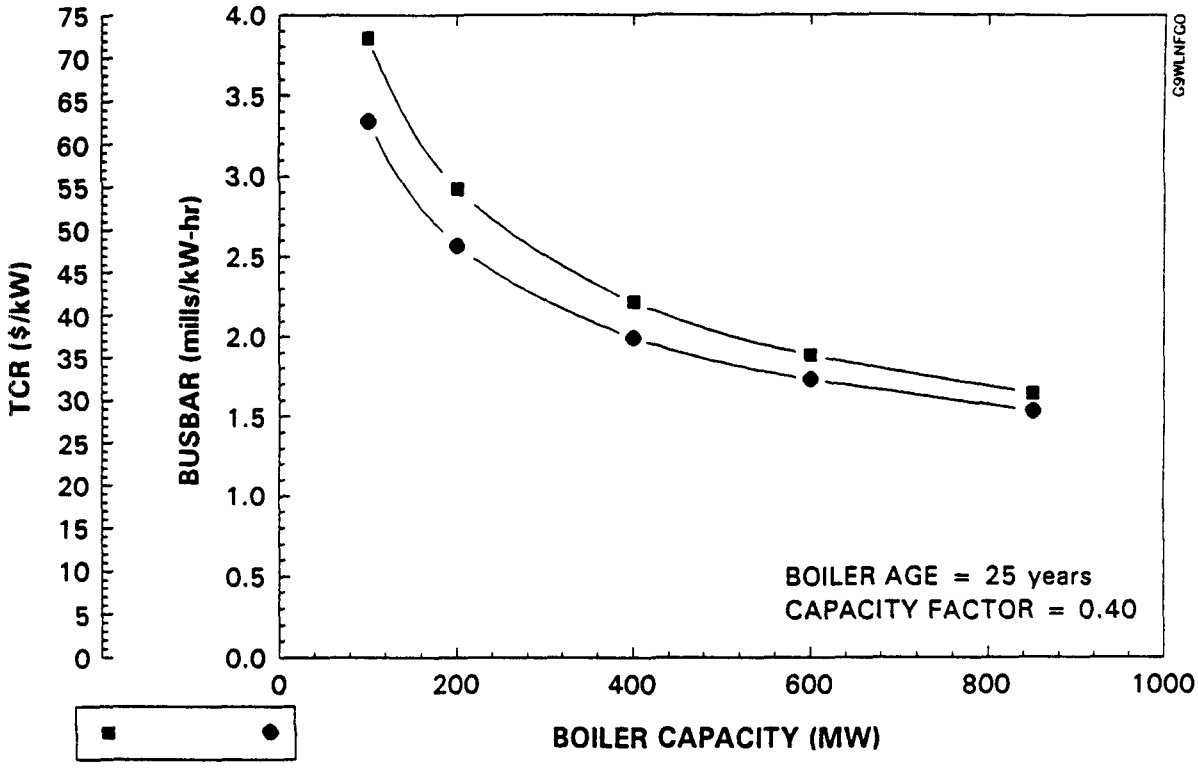


Figure 6-25. Capital and busbar cost of LNB + FGR + OFA for oil-/gas-fired boilers

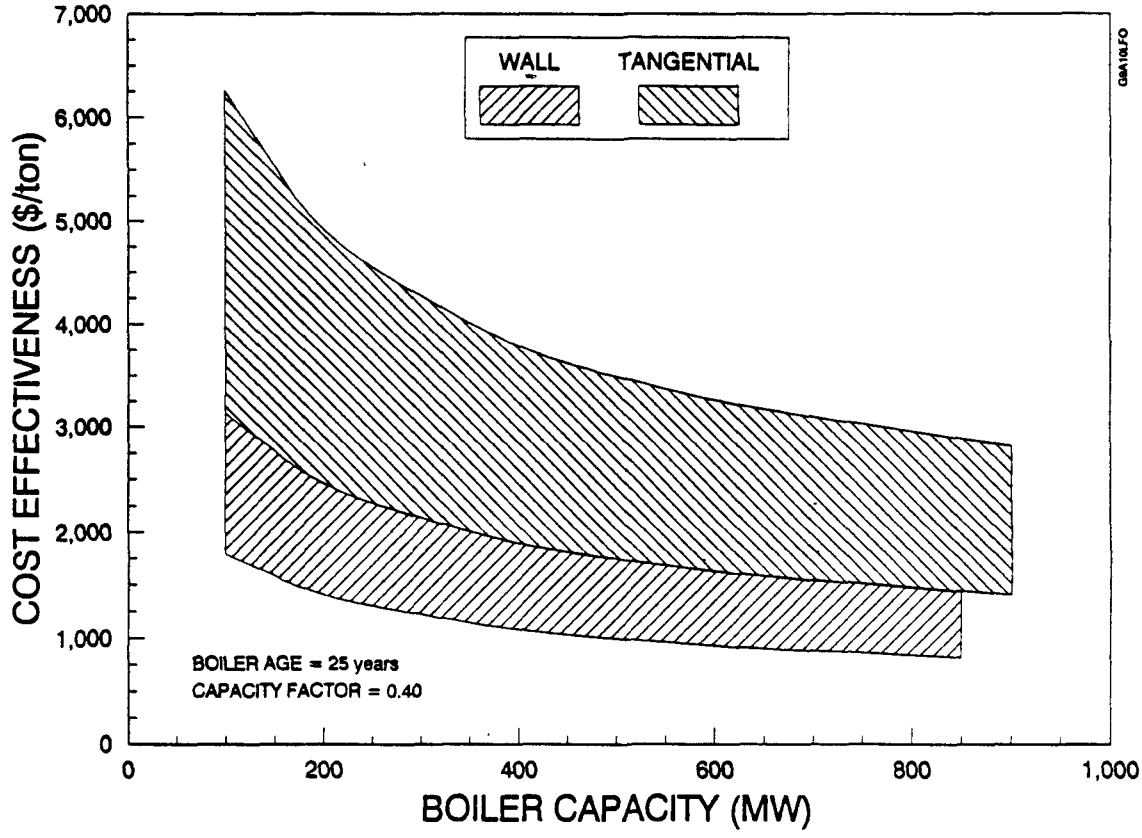


Figure 6-26. Cost effectiveness of LNB + FGR + OFA for wall and tangential oil-/gas-fired boilers

Table 6-5. Summary of combustion modification NO_x control costs for oil- and gas-fired utility boilers (1st Qtr $1991)

Boiler Firing Type	NO_x Control Technology	Uncontrolled NO_x Level[a] (lb/MMBtu)	Estimated Range in NO_x Control Levels[b] (lb/MMBtu)	Control Costs		
				Total Capital Requirement ($/kW)	Levelized Busbar (Mills/kWh)	Cost Effectiveness ($/ton)
Wall-firing	BOOS	0.45	0.30 - 0.35	0.61	0.18 - 0.20	230 - 510
	FGR	0.45	0.25 - 0.35	10	0.34 - 0.54	320 - 1,000
	LNB	0.45	0.25 - 0.30	28	0.80 - 1.3	750 - 1,700
	BOOS + FGR	0.45	0.25 - 0.30	11	0.46 - 0.68	440 - 850
	BOOS (OFA) + LNB + FGR	0.45	0.10 - 0.20	55	1.7 - 2.8	900 - 2,600
Tangential-firing	BOOS	0.30	0.20 - 0.25	0.61	0.18 - 0.20	340 - 740
	FGR	0.30	0.20 - 0.25	10	0.34 - 0.54	640 - 2,000
	LNB	0.30	0.15 - 0.25	28	0.80 - 1.4	1,000 - 5,100
	BOOS + FGR	0.30	0.15 - 0.20	11	0.46 - 0.68	580 - 1,300
	BOOS (OFA) + LNB + FGR	0.30	0.10 - 0.20	55	1.7 - 2.8	1,600 - 5,200

These costs were developed for the following conditions:
200 MWe for all boilers. (See Section 6 for effect of capacity on these costs)
Capacity factors = 40 to 65 percent
Boiler age 15 to 38 years

[a]Average baseline level for all wall- and opposed-fired boilers in NESCAUM. This average combines units listed as pre- and post-NSPS (See Table 3-4) and averages the value to the nearest 0.05 lb/MMBtu.
[b]Combustion-controlled levels are based on minimum and maximum percent NO_x reductions presented in Table 1-2 and Table 4-6 applied to the average baseline NO_x level of 0.45 lb/MMBtu for W-firing and 0.30 lb/MMBtu for T-firing.

Table 6-6. Summary of flue gas treatment NO_x control costs for coal-fired utility boilers (1st Qtr $1991)

Boiler Firing Type	NO_x Control Technology	Uncontrolled NO_x Level[a] (lb/MMBtu)	Estimated Range in NO_x Control Levels[b] (lb/MMBtu)	Control Costs		
				Total Capital Requirement ($/kW)	Levelized Busbar (Mills/kWh)	Cost Effectiveness ($/ton)
Wall-firing	SNCR on uncontrolled boilers	0.95	0.50 - 0.65	18	1.9 - 3.0	590 - 1,100
	SNCR on LNB-controlled boilers	0.60	0.35 - 0.45	18	1.0 - 1.4	760 - 1,680
	SCR on uncontrolled boilers[c]	0.95	0.15 - 0.25	192	7.0 - 12	1,650 - 3,220
	SCR on LNB-controlled boilers[c]	0.60	0.10 - 0.15	192	6.9 - 12	2,600 - 4,970
	SCR on LNB-controlled boilers[c,d]	0.60	0.15 - 0.20	148	5.1 - 9.1	2,100 - 4,250
Tangential-firing	SNCR on uncontrolled boilers	0.60	0.30 - 0.40	18	1.0 - 1.4	630 - 1,260
	SNCR on LNB-controlled boilers	0.45	0.25 - 0.35	18	0.84 - 1.2	790 - 2,200
	SCR on uncontrolled boilers[c]	0.60	0.10 - 0.15	192	7.0 - 12	2,600 - 4,970
	SCR on LNB-controlled boilers[c]	0.45	0.05 - 0.10	192	6.9 - 12	3,200 - 6,370
	SCR on LNB-controlled boilers[c,d]	0.45	0.10 - 0.15	148	5.1 - 9.0	2,700 - 5,600

These costs were developed for the following conditions:
200 MWe for all boilers. (See Section 6 for effect of capacity on these costs)
Capacity factors = 40 to 82 percent for wall and tangential units, 55 to 83 percent for cyclones
Boiler age 20 to 40 years for wall and tangential units, 27 years for cyclones

[a]See Table 3-4 for average baseline levels in the NESCAUM Region. Only pre-NSPS units are considered.
[b]See Tables 1-1 and 1-3, Section 4 and Appendix D for estimated range in controlled NO_x levels.
[c]Cost of SCR retrofit based on catalyst unit cost of $660/ft^3 and life of 4 years. Effects of other catalyst cost and life are discussed in Section 6.
[d]SCR installed at the economizer outlet (hot-side case). All other SCR cases are for catalyst reactor installed downstream of particulate and FGD controls (cold-side).

Table 6-7. Summary of flue gas treatment NO_x control costs for gas- and oil-fired utility boilers (1st Qtr $1991)

Boiler Firing Type	NO_x Control Technology	Uncontrolled NO_x Level[a] (lb/MMBtu)	Estimated Range in NO_x Control Levels[b] (lb/MMBtu)	Control Costs		
				Total Capital Requirement ($/kW)	Levelized Busbar (Mills/kWh)	Cost Effectiveness ($/ton)
Wall-firing	SNCR on uncontrolled boilers	0.45	0.25 - 0.30	8.0	0.71 - 0.87	670 - 1,100
	SNCR on BOOS+FGR controlled boilers	0.30	0.20 - 0.25	8.0	0.54 - 0.69	1,000 - 2,600
	SCR on uncontrolled boilers[c]	0.45	0.10 - 0.15	135	4.8 - 7.9	2,600 - 4,900
	SCR on BOOS+FGR controlled boilers[c]	0.30	0.05 - 0.10	135	4.8 - 7.9	3,600 - 7,400
Tangential-firing	SNCR on uncontrolled boilers	0.30	0.15 - 0.20	8.0	0.54 - 0.69	670 - 1,300
	SNCR on LNB-controlled boilers	0.20	0.10 - 0.15	8.0	0.43 - 0.58	800 - 2,200
	SCR on uncontrolled boilers[c]	0.30	0.05 - 0.10	135	4.8 - 7.9	3,600 - 7,400
	SCR on LNB+FGR controlled boilers[c]	0.20	0.05 - 0.10	135	4.8 - 7.9	6,000 - 15,000

These costs were developed for the following conditions:
200 MWe for all boilers. (See Section 6 for effect of capacity on these costs)
Capacity factors = 40 to 65 percent
Boiler age 15 to 38 years

[a]Average baseline level for all wall- and opposed-fired boilers in NESCAUM. This average combines units listed as pre- and post-NSPS (See Table 3-4) and averages the value to the nearest 0.05 lb/MMBtu.

[b]Combustion-controlled levels are based on minimum and maximum percent NO_x reductions presented in Table 1-2 and Table 4-6 applied to the average baseline NO_x level of 0.45 lb/MMBtu for W-firing and 0.30 lb/MMBtu for T-firing. For FGT controls, the range in controlled NO_x levels is based on estimates presented in Table 1-3.

[c]Cost of SCR based on catalyst life of 6 years.

fired boilers, to 0.10 to 0.20 lb/MMBtu, for PC-fired units. When SCR is applied to uncontrolled boilers, the limits of the SCR technology are estimated to range between 0.05 to 0.15 lb/MMBtu, for oil-/gas-fired boilers, and 0.10 to 0.25 lb/MMBtu, for PC-fired boilers.

Figures 6-27 through 6-36 illustrate the economic data developed for these FGT applications for different boiler capacities. These costs are highly speculative considering the limited application and experience in the United States. The following subsections highlight the basis for these cost estimates and briefly discuss the results. Details on line item costs can be found in Appendix F, for PC-fired boilers, and in Appendix G, for oil-/gas-fired boilers.

6.3.1 Selective Noncatalytic Reduction (SNCR) Costs

Capital cost and cost-effectiveness for SNCR applications on PC-fired boilers are shown in Figures 6-27 through 6-29. Estimates are for boilers already controlled with the most effective combustion modifications, and for boilers currently uncontrolled. The capital requirement of the SNCR process is reported to vary widely, from $4/kW (Teixeira, 1992) to $27/kW (Hunt, 1992). For PC-fired boilers, the capital cost for this study was based on two recent estimates, one for the NOXOUT process retrofitted on WEPCO Valley Power Plant 89-MWe Unit 3, for which the capital requirement was reported at about $28/kW (Nalco, 1992), and the other for a coal-fired 100-MWe boiler at PSC Arapahoe Unit 4, for which the capital requirement was reported as high as $27/kW (Hunt, 1992).

For a 200-MWe boiler, these estimates translate to about $18/kW, as shown in Table 6-6. Levelized busbar costs for SNCR processes are principally the annualized capital costs and the costs of reagent use, which vary linearly with degree of NO_x reduction. The calculated cost effectiveness for SNCR ranges from about $590/ton to $1,300/ton, for uncontrolled PC-fired boilers, to $760/ton to $2,200/ton, for those PC boilers whose NO_x emissions have already been reduced with combustion controls to levels of 0.60 lb/MMBtu, for wall-fired units, and 0.45 lb/MMBtu, for tangential-fired units.

For oil-/gas-fired units, the capital cost of SNCR retrofit was based on recent estimates provided by PG&E on the basis of a recent field test demonstration on Morro Bay 350-MWe Unit 3 (Teixeira, 1992). During that study, the retrofit capital cost was estimated to range between $5 and $10/kW. This estimate agrees with that of SCE for low-energy urea (Johnson, 1991). On this cost premise, the overall cost effectiveness for SNCR on a 200-MWe oil-/gas-fired boiler was calculated to range between $670/ton and $1,300/ton, for uncontrolled units, to about $1,000/ton to $2,600/ton, for combustion-controlled units. The cost effectiveness is little influenced by the size, age, and capacity of the boiler because reagent cost is the dominant portion of the overall busbar cost.

6.3.2 Selective Catalytic Reduction (SCR) Costs

SCR is the most expensive option for reducing NO_x from existing utility boilers. Recent SCR cost estimates from applications of the technology show that the retrofit TCR for coal-fired power plants has ranged from $60/kW to $189/kW in Germany and $35/kW to $80/kW in Japan (Lowe, 1991). The German experience is based on retrofit of generally hot-side SCR systems on older, more congested power plants sites. SCE is evaluating the cost and technical feasibility of low-cost SCR-based alternatives. One such technology, already under demonstration in Germany and

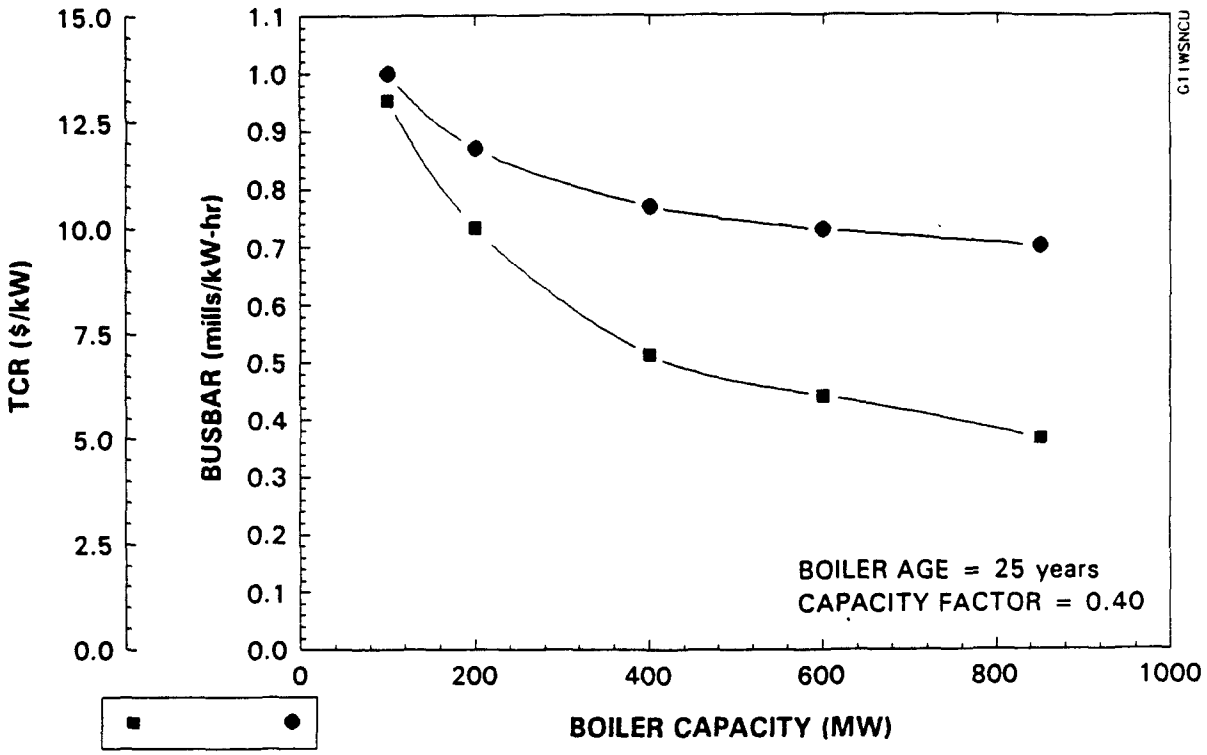


Figure 6-27. Capital and busbar cost of SNCR for coal-fired utility boilers

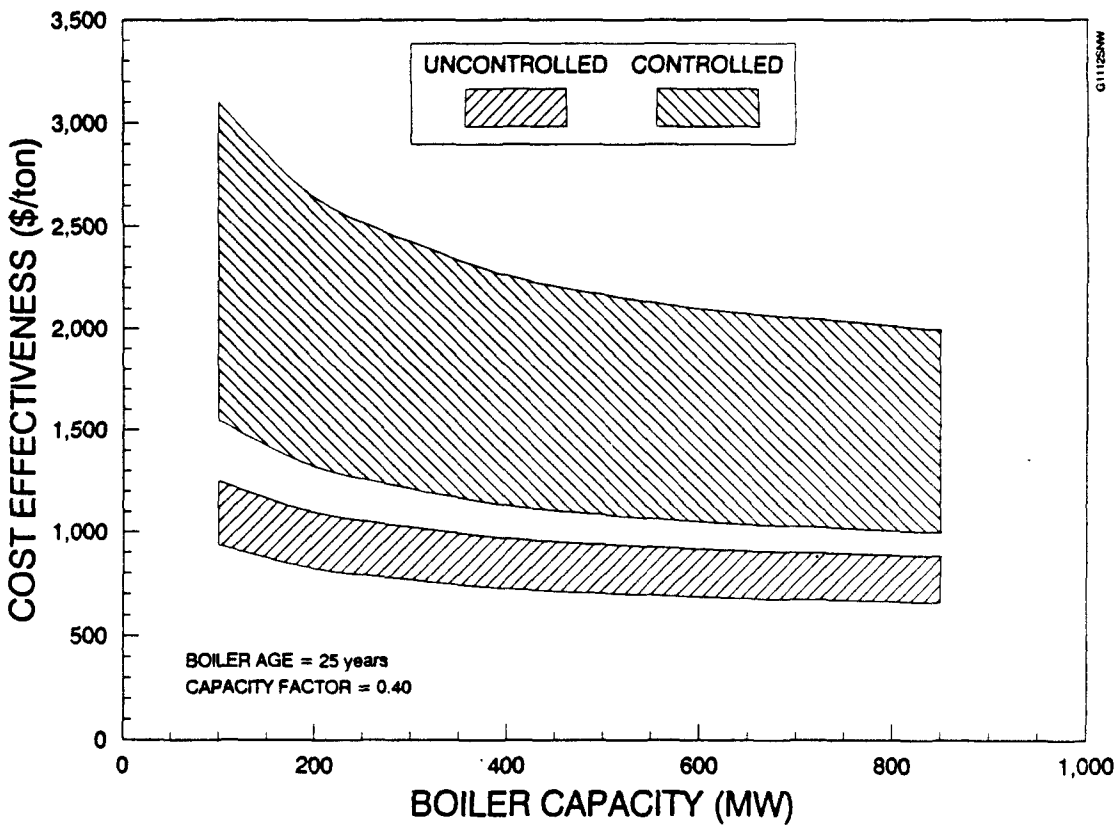


Figure 6-28. Cost effectiveness of SNCR for uncontrolled and LNB-controlled wall coal-fired utility boilers

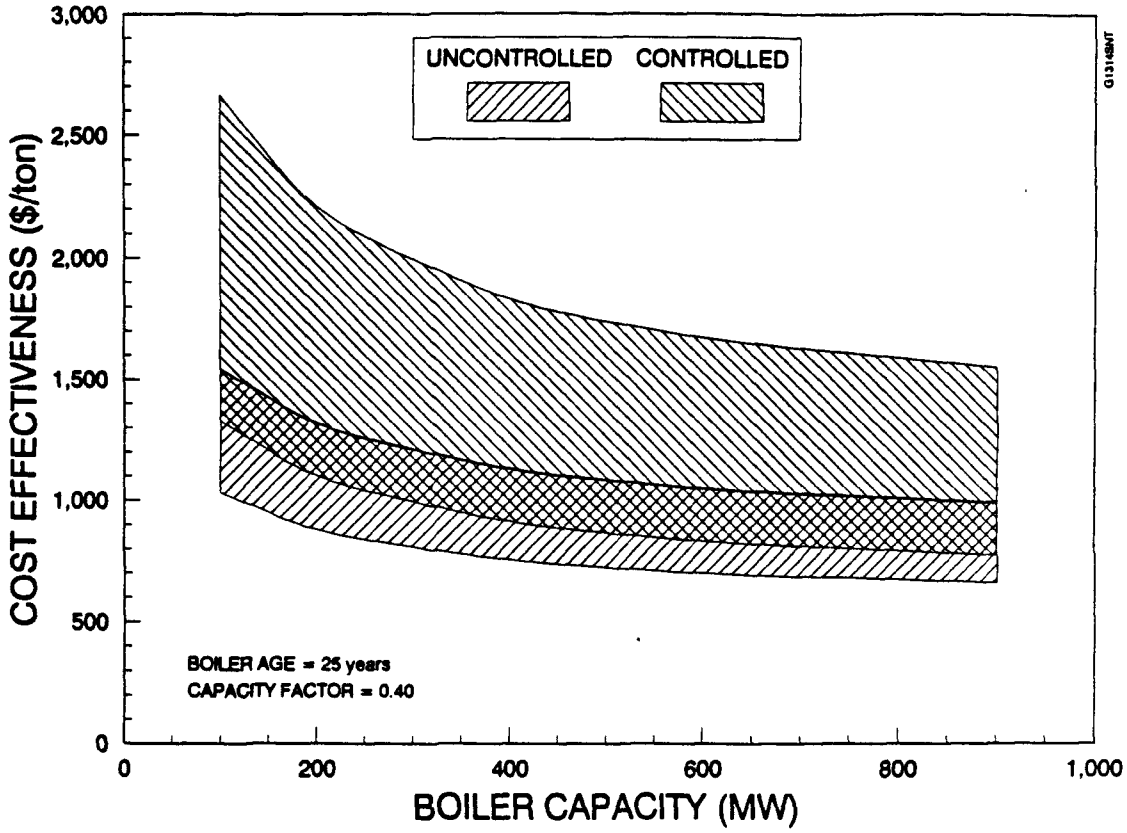


Figure 6-29. Cost effectiveness of SNCR for uncontrolled and LNB-controlled tangential coal-fired utility boilers

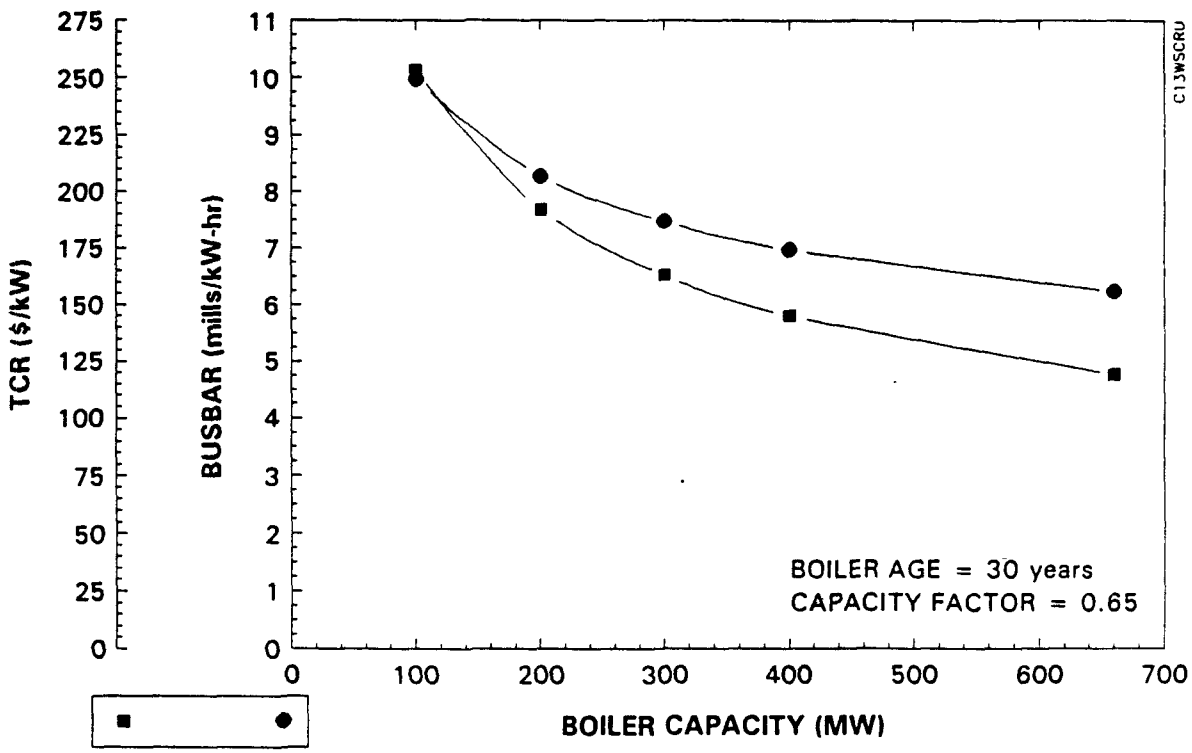


Figure 6-30. Capital and busbar cost of cold-side SCR for coal-fired utility boilers

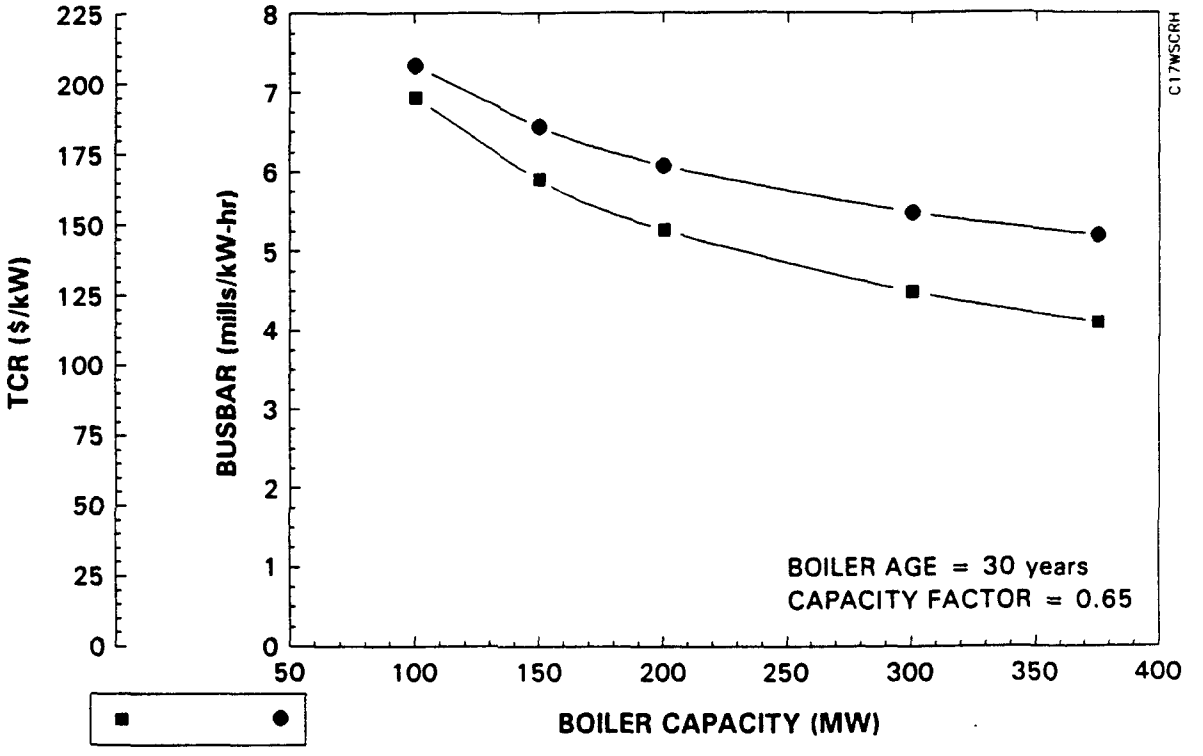


Figure 6-31. Capital and busbar cost of hot-side SCR for coal-fired utility boilers

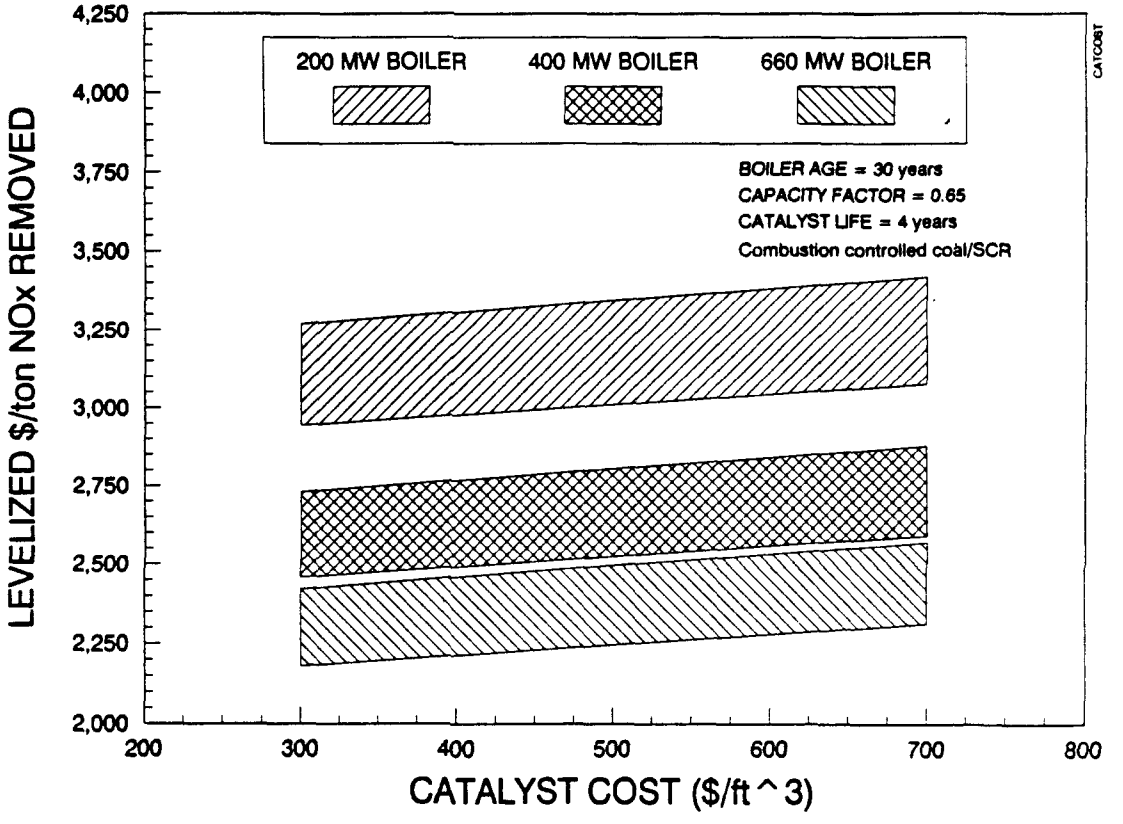


Figure 6-32. Cost effectiveness of cold-side SCR for coal-fired utility boilers—effect of catalyst unit cost

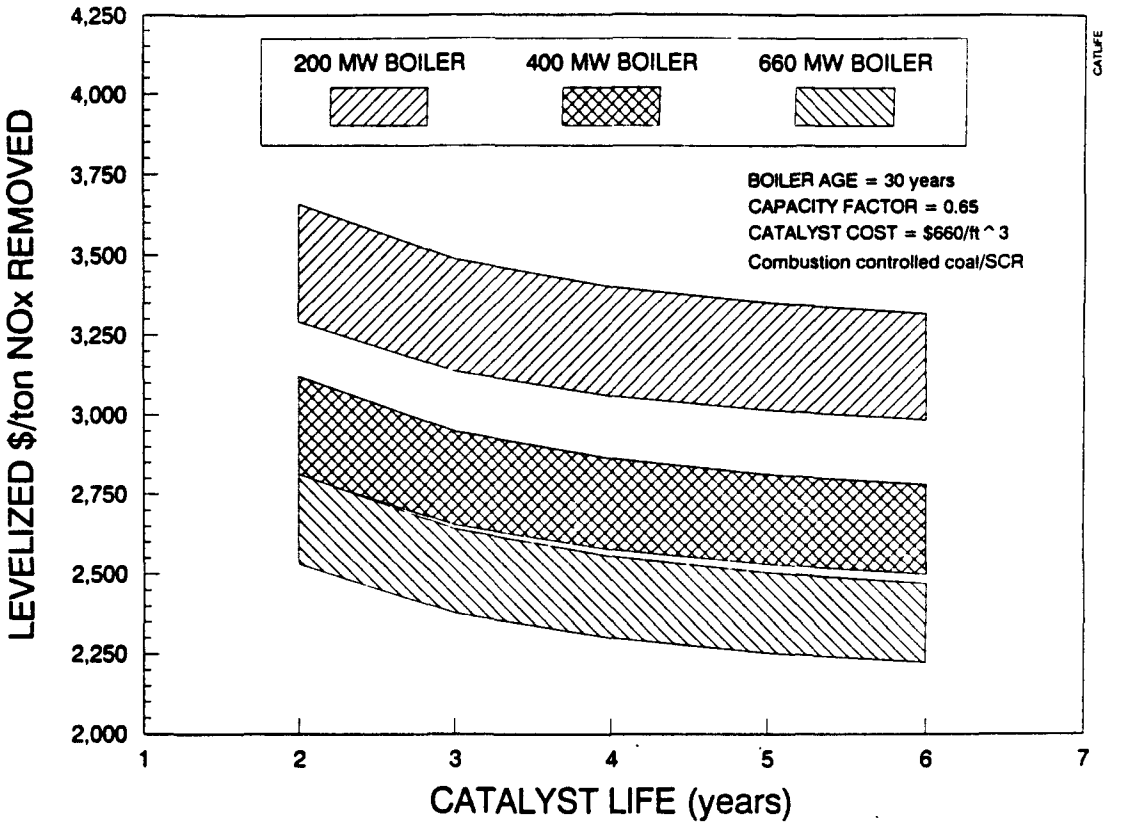


Figure 6-33. Cost effectiveness of cold-side SCR for coal-fired utility boilers—effect of catalyst life

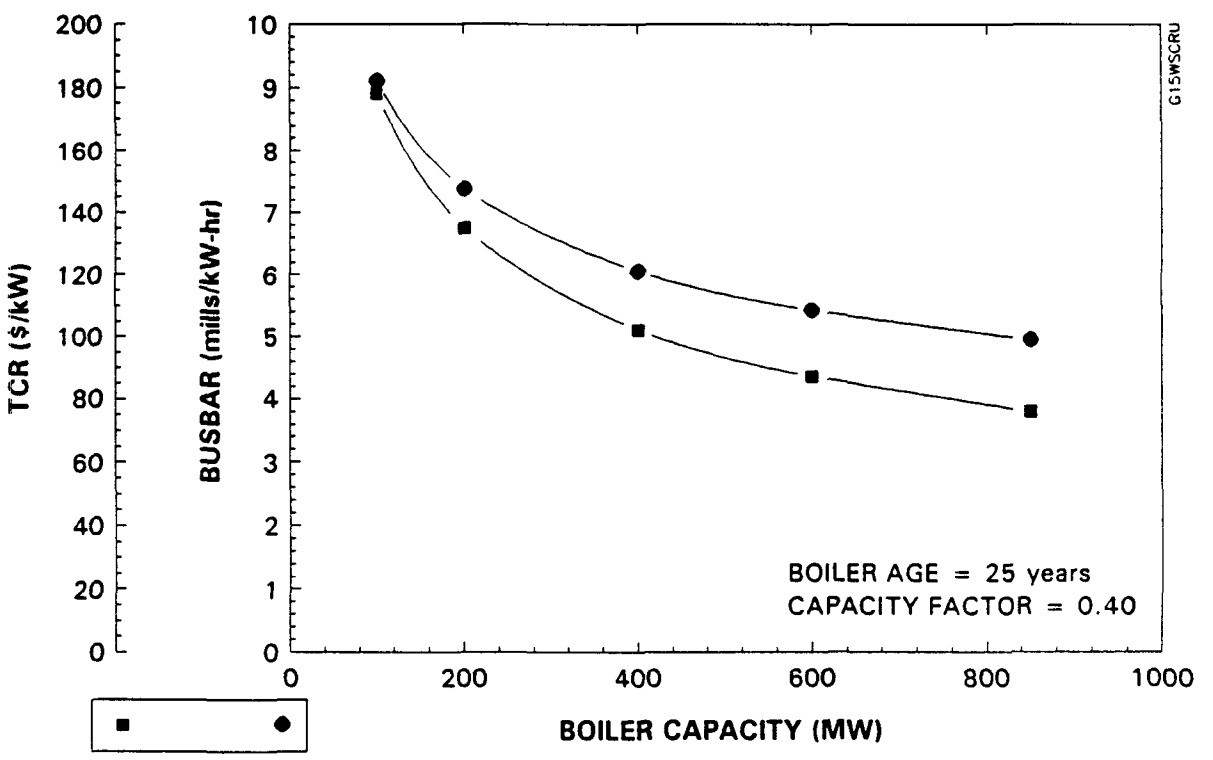


Figure 6-34. Capital and busbar cost of SCR for oil-/gas-fired utility boilers

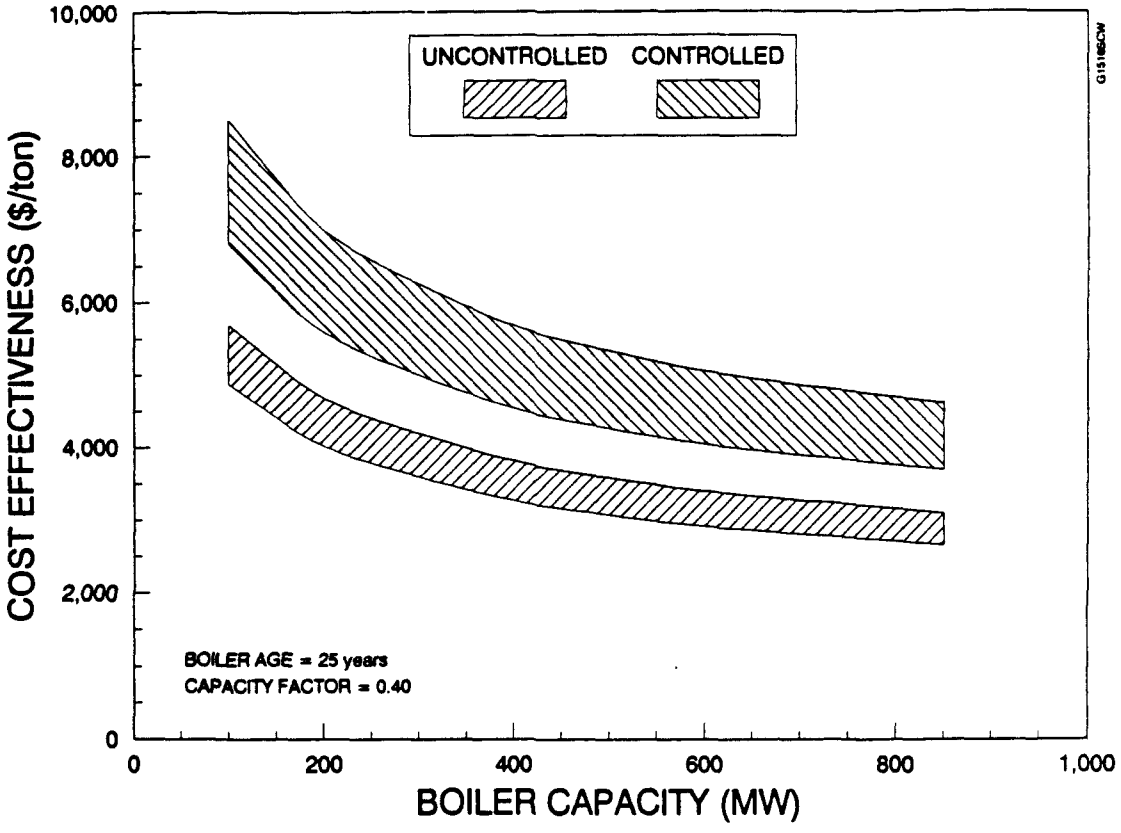


Figure 6-35. Cost effectiveness of SCR for uncontrolled and combustion-controlled wall oil-/gas-fired boilers

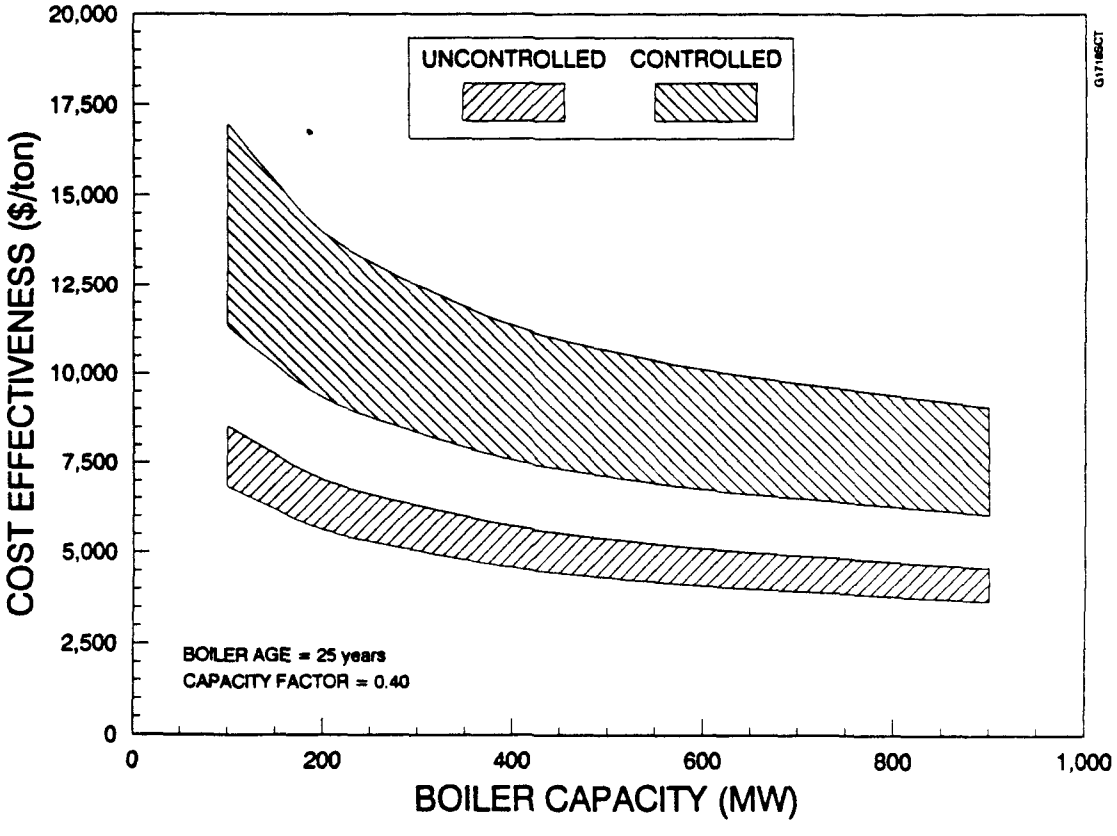


Figure 6-36. Cost effectiveness of SCR for uncontrolled and combustion-controlled tangential oil-/gas-fired boilers

at SCE's Mandalay Unit 2, is the air heater SCR (CAT-AH) system which is reported to have a NO_x reduction efficiency in the range of 30 to 80 percent and a potential capital cost of only \$23/kW (Reese, 1992; Johnson, 1991). The upper range in NO_x reduction performance was reported for a combination of urea-SNCR with CAT-AH. The combination of urea-SNCR with small downstream catalyst, such as the CAT-AH, may prove a viable economic alternative to SCR systems in some retrofit cases.

Tables 6-6 and 6-7, and Figures 6-30 through 6-36, present cost estimates for SCR for several retrofit cases, including hot- and cold-side catalyst installation, uncontrolled and controlled boilers, and varying assumptions on catalyst unit cost and durability. For PC units, the economic data for SCR retrofit (both hot- and cold-side) were based on detailed cost estimates prepared by EPRI (Robie, 1991). For oil-/gas-fired units, capital costs of SCR were based on estimates prepared by SCE (Johnson, 1991). Most of the SCR costs presented here are based on catalyst unit pricing of \$660/ft^3 and a life of 4 to 6 years for PC and oil-/gas-fired boiler applications, respectively.

The total capital requirement for SCR retrofit on the average size 200-MWe PC-fired unit in NESCAUM is estimated to be about \$150/kW, for hot-side, and \$190/kW, for cold-side. The cost effectiveness for uncontrolled units is estimated to range between \$1,700/ton and \$5,000/ton, depending on the quantity of NO_x reduced. The cost effectiveness escalates to about \$6,400/ton for NO_x reductions from combustion-controlled levels. Figures 6-32 and 6-33 illustrate some important relationships between cost-effectiveness and catalyst unit cost and durability. By halving the catalyst unit price from \$660/ft^3 to about \$300/ft^3 and extending its life from 4 to 6 years, the overall cost effectiveness is reduced by a combined amount of about 15 percent. This effect is minor compared to changes in cost effectiveness due to boiler size and NO_x reduction efficiency.

For 200-MWe oil-/gas-fired boilers, the retrofit of SCR is estimated to average \$135/kW and result in cost effectiveness in the range of \$2,600/ton to \$7,400/ton, for uncontrolled boilers, and \$3,600/ton to \$15,000/ton, for combustion-controlled units. As illustrated in Figures 6-35 and 6-36, the cost effectiveness of these retrofits is highly variable with boiler size because of the influence of the initial investment on the overall busbar cost.

6.4 SUMMARY OF CONTROL COSTS

Figures 6-37 and 6-38 illustrate the economic data for all of the control retrofit cases for coal-fired boilers investigated in this study. A standard boiler size of 200 MWe for PC-fired units was selected for this comparison. The information on NO_x control level clearly indicates that NO_x emissions below 0.35 to 0.55 lb/MMBtu, for wall-fired boilers, and 0.25 to 0.45 lb/MMBtu, for tangential boilers, are not achievable without the added control afforded by FGT technologies. In reality, as discussed in Section 4, combustion modification retrofits are unlikely to attain the low end of these NO_x targets, and only higher control levels are considered possible with commercially available technologies. The cost effectiveness of LNB and LNB+OFA control technologies would likely not exceed \$1,000/ton for wall-fired boilers, and be slightly higher for tangential units. For larger size boilers, the total capital requirement in \$/kW and cost effectiveness will be lower. All other controls have higher costs per ton of NO_x removed compared to LNB and LNB+OFA controls. The data also illustrate that, among these other controls, both NGR and SNCR on uncontrolled boilers have estimated cost effectiveness levels equivalent to those of combustion modifications.

Figure 6-39 illustrates the cost effectiveness of controls for a 200-MWe wall oil-/gas-fired boiler; Figure 6-40 illustrates the same for a 200-MWe tangential oil-/gas-fired boiler. Controlling

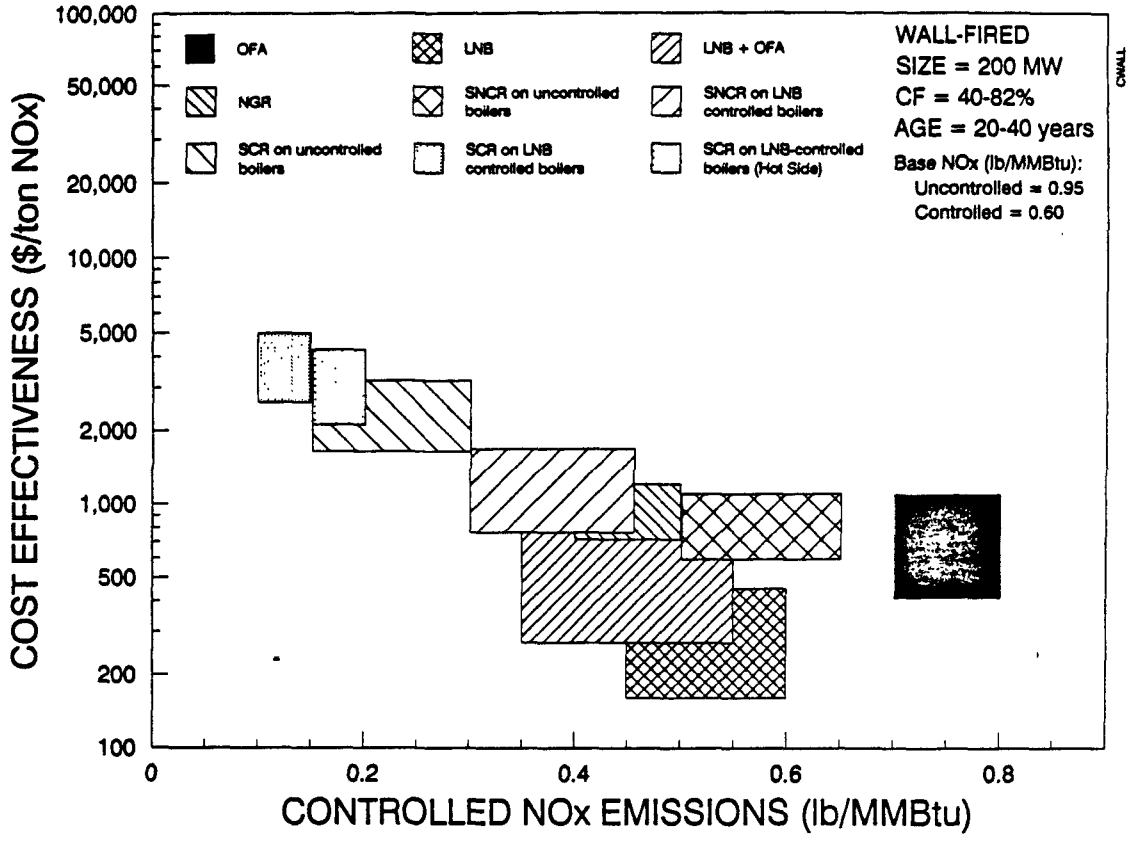


Figure 6-37. NO_x control cost-effectiveness for PC wall-fired utility boilers

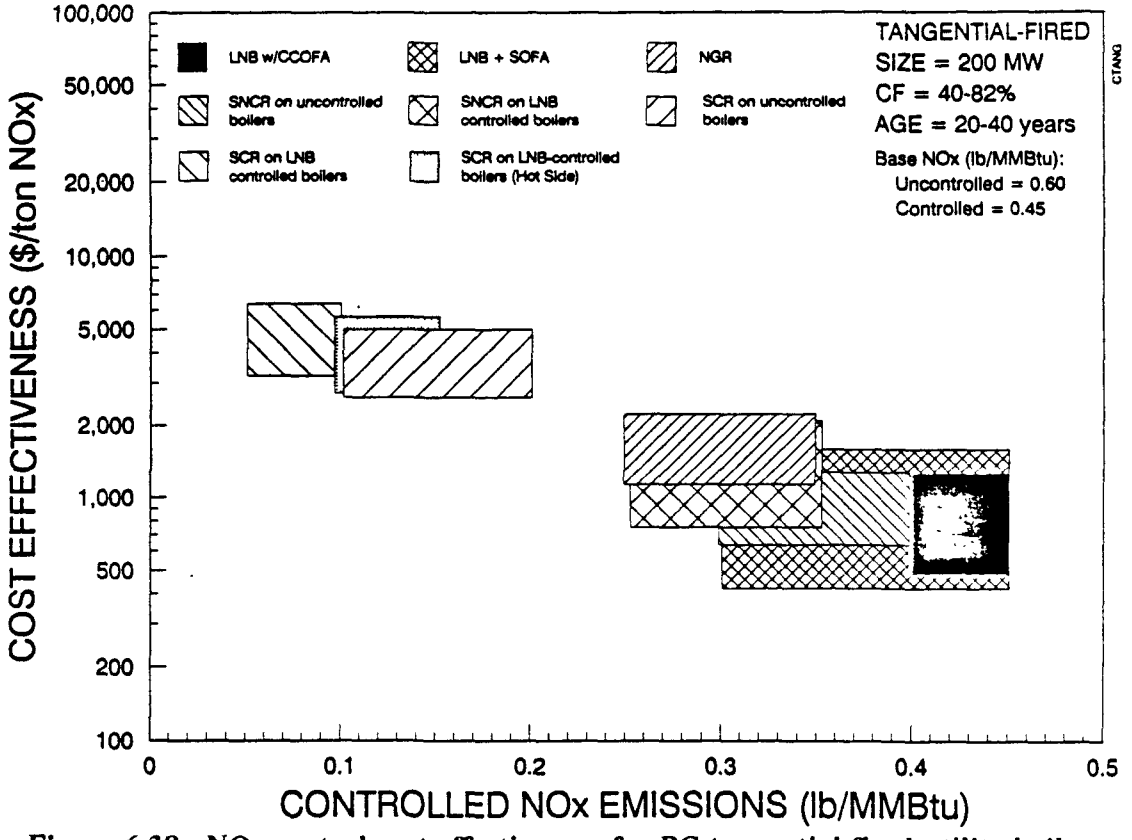


Figure 6-38. NO_x control cost-effectiveness for PC tangential-fired utility boilers

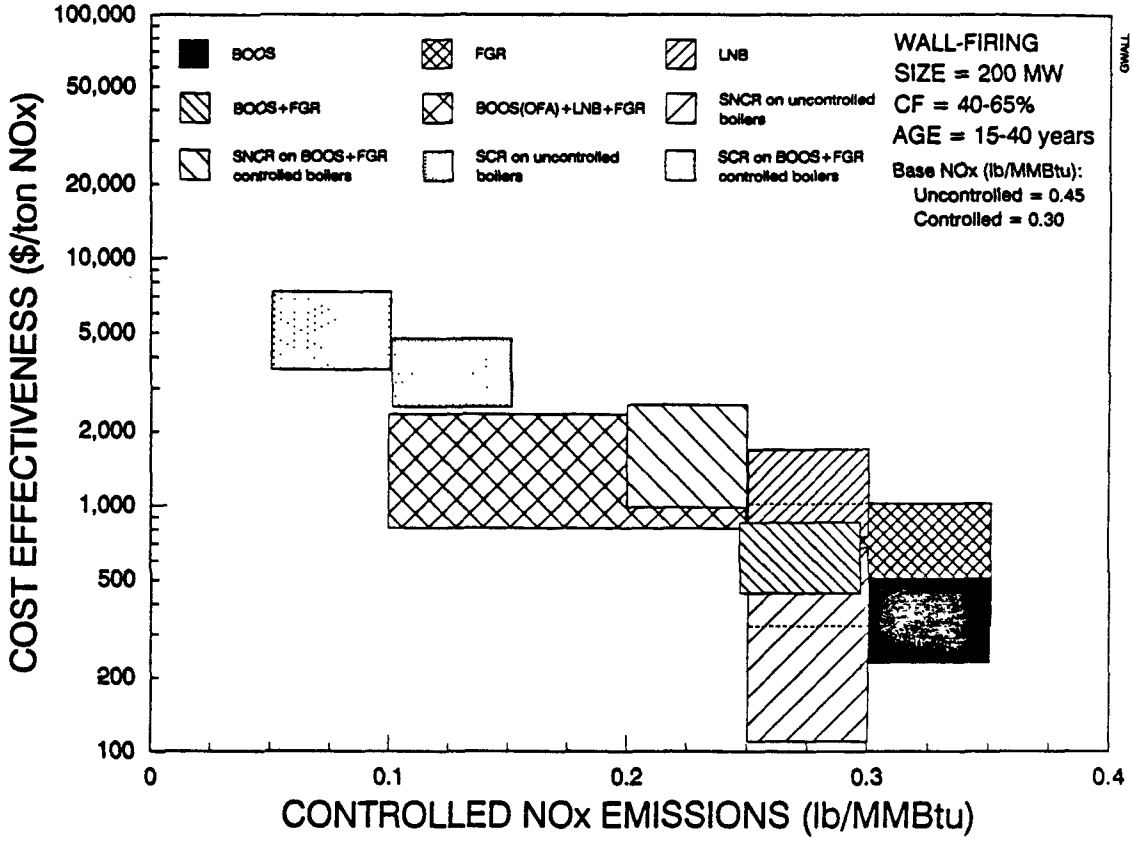


Figure 6-39. NO_x control cost-effectiveness for oil/gas wall-fired utility boilers

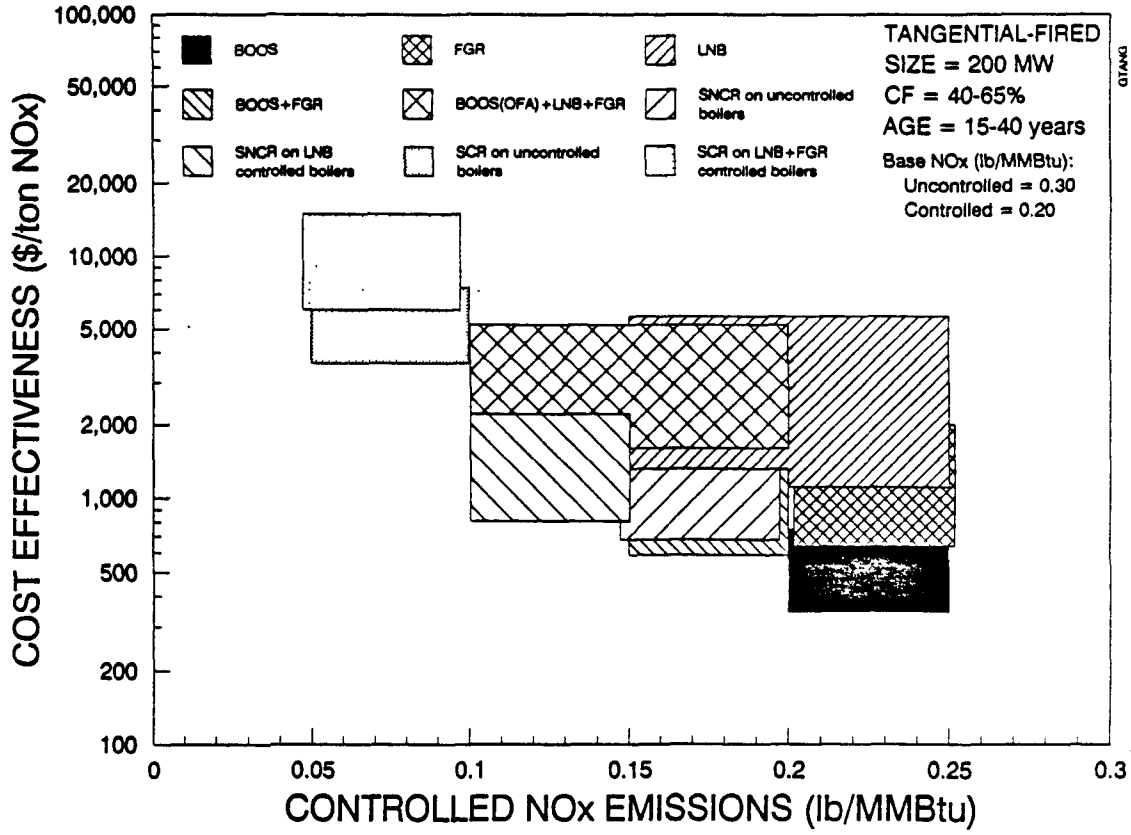


Figure 6-40. NO_x control cost-effectiveness for oil/gas tangential-fired utility boilers

NO_x emissions to levels as low as 0.25 lb/MMBtu (about 200 ppm) is estimated to cost less than $1,000/ton. Lower costs are anticipated for larger capacity boilers. Significant NO_x reductions from low NO_x levels of tangential units are anticipated to cost more than $1,000/ton, with the possible exception of BOOS and FGR. The cost of further NO_x reductions from these units will be much higher regardless of the control option.

Because of uncertainty in cost assumptions used in this study, and in reported costs for some control technologies with limited operational experience, these estimates are offered only as guidelines. Actual costs can be much different depending on the ease of retrofit; the extent of equipment modifications; and the control's performance, including operational impacts.

SECTION 7

EFFECTS OF NO_x CONTROLS ON COMBUSTION EFFICIENCY AND RELATED EMISSIONS

The reduction in peak flame temperature and the delayed mixing of fuel with combustion air needed to suppress both thermal and fuel NO_x formation can result in a decrease in both combustion and thermal efficiencies, therefore this must be considered during the design phase of NO_x retrofits to minimize these impacts. In oil- and gas-fired boilers, combustion efficiency losses are indicated by concentrations of CO, THC, and soot (opacity) in the stack gas. In PC-fired boilers, reduction in combustion efficiency is evidenced primarily by an increase of the UBC in the flyash. Along with its associated efficiency loss, the increased concentration of UBC in the flyash can alter the properties of the ash, affecting the performance of the electrostatic precipitator, and ultimately the emissions of fine particulate from the stack. Also, increasing UBC levels can make the ash unsalable, resulting in a significant ash disposal cost for some plants that currently sell the ash for cement production.

If unchecked, flue gas CO, THC, and soot emissions can have an adverse effect on the environment in addition to decreasing system performance. For example, the NESCAUM region contains nonattainment areas for CO and PM_{10}, as well as for ozone. Therefore, it is important to understand the effects of retrofit controls on these emissions and to identify the range of NO_x reduction that can be achieved without adversely affecting the levels of these other emissions.

The principal indicators of combustion efficiency in utility boilers are CO and stack opacity for oil-/gas-fired boilers, and CO emissions and UBC content of the flyash for PC-fired units. When burning natural gas and high grade fuel oils in utility boilers, CO emissions will usually increase first before any measurable amount of THC or soot is emitted (Radak, 1991). When burning residual oil, large increases in CO emissions are followed by increases in soot formation that contribute to opacity haze at the stack outlet. THC emissions, as measured by conventional analyzers, are typically very low for utility boilers, irrespective of fuel. In most cases, significant increases in CO are necessary to record increases in gaseous THC. Consequently, CO emissions are often considered a precursor to THC emissions and are thus routinely monitored, whereas THC emissions normally are not. Since large quantities of CO and UBC mean decreased combustion efficiency, utility boilers are normally operated to keep CO and UBC levels at a minimum (Steam, 1978), thereby precluding any significant levels of THC emissions.

This section summarizes the reported efforts of utility boiler retrofit combustion modification controls on emissions of CO for all fuel types (natural gas, oil, and coal), and on the levels of UBC in the flyash of PC-fired boilers. Appendix H provides a tabulated summary of the data presented in this section. It is not the intent of this section to develop a correlation between CO and NO_x and THC and NO_x but rather to provide some overall guidelines on the potential effect of NO_x controls on combustible emissions.

7.1 CO EMISSIONS AND UNBURNED CARBON FROM COAL-FIRED UTILITY BOILERS

7.1.1 CO Emissions

Tables 7-1 through 7-3 summarize CO emissions and UBC data for 25 coal-fired boilers of various firing type, the majority being wall-fired. For several boilers, the data show increased CO emissions with decreased NO_x levels. The tables also show that the relationships between NO_x and CO emissions are very boiler-specific and depend, for example, on firing configuration and capacity, fuel type, furnace heat release rate, control type, and air/fuel distribution.

Figure 7-1 shows NO_x and CO data for Ohio Edison's Edgewater Unit 4, a 100 MW wall-fired boiler retrofitted with LNBs. Installation of LNBs reduced NO_x by 25 percent initially, with a corresponding 475 percent increase in CO to 115 ppm, relative to pre-retrofit baseline emission levels. LNB optimization adjustments produced an additional 9 percent NO_x reduction from baseline, and post-retrofit CO emissions were lowered to 60 ppm.

This LNB retrofit program showed the importance of accurate air/fuel control to low-NO_x combustion optimization. During LNB optimization, further balancing and tuning of the combustion system was hampered by significant variations in air/fuel distribution. These imbalances resulted in unacceptably high CO and UBC when further NO_x reduction was pursued. It was concluded that these "high performance low NO_x burners can reach their potential only when used in combination with systems which accurately and consistently regulate their air and fuel supply" (LaRue, 1989). The original pre-NSPS rapid mix burners were less sensitive to inaccuracies in air/fuel distribution, and did not experience significant combustion inefficiencies.

Tests at Germany's RWE utility boiler show increased CO when NO_x was reduced below about 125 ppm (0.17 lb/MMBtu) during OFA operation. These data are shown in Figure 7-2. The boiler operating variable used in these tests was the excess air level (Hein, 1989; Allen, 1991). With OFA and with excess air levels above 20 percent, CO emissions remained constant at 20 ppm, while the lowest NO_x emission level was 150 ppm (0.2 lb/MMBtu)—roughly 50 percent NO_x reduction when compared to baseline. CO emissions for the same air levels but without OFA were approximately 10 ppm. Once excess air was reduced below 20 percent, CO emissions increased at a rapid rate during both baseline and low NO_x operation. For example, an additional 50 ppm (0.07 lb/MMBtu) NO_x reduction resulted in CO increase to 240 ppm. Thus, comparing low NO_x to baseline operation, there was little increase in CO until very low excess air levels were reached. This boiler was fired on German brown coal, thus the emission levels reported may not be representative of boilers firing U.S. coals. However, the data illustrate the relative change in CO when NO_x controls are implemented.

Similar results were recorded with tests performed by NEI-International Combustion Limited (NEI-ICL) on a 500 MW unit equipped with LNB. These data, shown in Figure 7-3, show little or no effect of NO_x reduction on CO until controlled NO_x levels below 300 ppm (0.4 lb/MMBtu) were reached; corresponding to NO_x reduction of about 50 percent from baseline.

Tests on Allegheny Power's Pleasants Unit 2 illustrate that the use of LNB in place of OFA resulted in more efficient combustion conditions. When OFA was used, a 30-percent reduction in NO_x occurred along with a 50 percent increase in CO. When LNBs were retrofitted without the use of OFA, 57-percent NO_x reduction was demonstrated with no increase in CO. A combination

Table 7-1. Sample of baseline/controlled CO and UBC data, wall-fired PC boilers

Boiler ID	Capacity (MWe)	Coal Type	NO_x Control	NO_x (lb/MMBtu)[a]	CO (ppm @ 3% O_2)	UBC (%)	Reference
Asnaes 4, Denmark	285	Polish	Baseline	0.99[b]	NA[c]	5	Pederson, 1991
			LNB	0.49[b]	NA	<5	
BHK, Japan	360	Japanese/Canadian	Baseline	0.30-0.32	NA	7.5-10	Morita, 1989
			LNB	0.21-9.29	NA	3.8-8.3	
Drax G, U.K.	660	U.K. Bituminous	Baseline	1.11	NA	1-1.5	King 1991
			LNB	0.44-0.58	NA	1-6.5	
Edgewater 4, OH	100	U.S. E Bituminous	Baseline	0.71	20	2.2	LaRue 1989
			LNB	0.47-0.53	60-115	2.8-6	
Eggborough 2, U.K.	500	U.K.	Baseline	0.84-1.03	NA	1.2-2.5	Beard 1989
			LNB	0.45-0.60	NA	2.5-7.2	
Four Corners 4, NM	800	U.S. Subbituminous	Baseline	1.27	<40	0.1	Vatsky, Lu
			LNB	0.50	20-40	0.1	1991
Hammond 4, GA	500	U.S. E Bituminous	Baseline	1.0-1.2[b]	30-100[b]	4.5-5.2	Wilson 1991
			LNB	0.55-0.7[b]	10-20[b]	5.5-8	Sorge 1992
			AOFA	0.9-0.95[b]	10-15[b]	9.5-10	
			LNB+AOFA	0.54	NA	11.0	
Inkoo 4, Finland	265	U.S.	Baseline	1.0	NA	3	Vemura 1991
			LNB	0.32-0.44	NA	6.3-8.5	
Maas 5, Netherlands	166	Cerrejon	Baseline	0.56-0.96[b]	NA	0.8-4.5	Vanderkooij
			LNB+OFA	0.33-0.40[b]	NA	2.5-13	1991
NEI-ICL, U.K.	500	U.K.	Baseline	0.73-0.91	20-80	2.1-5.2	Allen 1991
			LNB	0.36-0.64	9-50	0.8-7.0	
Pleasants 2, PA	650	U.S. E. Bituminous	Baseline	0.95	40	2.5	Vatsky 1989
			LNB	0.41	40	2.5	
			OFA	0.65	40-60	2.5	
			LNB+OFA	0.33	100	NA	
Stuart 4, OH	600	U.S. Ky Bituminous	Baseline	1.17[b]	30[b]	1.1-2.5	Laursen 1992
			LNB	0.53[b]	41[b]	2.9	
Gaston 2, AL	250	M.W. Bituminous	Baseline	0.50-0.78	NA	5.5-7.0	Hardman,
			LNB	0.30-0.40	NA	5.6-10.0	1992
RWE, Germany	600	German brown	Baseline OFA	0.26-0.45	10-400	NA	Hein 1989
				0.13-0.27	20-260	NA	
Vado Ligure 4, Italy	330	U.S. Bituminous	Baseline	0.78-0.93	NA	5.5-6	Tarli 1991
			OFA	0.52-0.63	8	7.7-12	

[a]To convert to ppm @ 3% O_2, multiply by 750.
[b]Long-term test data.
[c]No data available.

Table 7-2. Summary of baseline/controlled CO and UBC data, tangential-fired PC boilers

Boiler ID	Capacity (MWe)	Coal Type	NO_x Control	NO_x (lb/MMBtu)[a]	CO (ppm @ 3% O_2)	UBC (%)	Reference
Cherokee 4, CO	350	U.S. W. Bituminous	Baseline	0.45-0.54	30	4.4-2.2	Hunt 1991,
			LNB+OFA	0.32	39	1.9-2.5	1992
Fusina 2, Italy	160	U.S. E. Bituminous	Baseline	0.68	NA[b]	5.9	Grusha 1991
			LNB+OFA	0.34	40	7.5	Ghiribelli 1992
Hennepin 1, IL	71	U.S. Bituminous	Baseline	0.73	NA	NA	May 1992
			NG return+OFA	0.28[c]	10[c]	NA	
Labadie 4, MO	600	U.S. Bituminous/	Baseline	0.50-0.69	5-35	0.5-1.0	Smith 1992
		Subbituminous	LNB+OFA	<0.45	NA	NA	
Lansing Smith 2, FL	200	U.S. E. Bituminous	Baseline	0.6-0.65[c]	10-15[c]	4.4-5	Hardman 1992
			LNB+OFA	0.4[c]	20-32[c]	3.8-5.4	
			LNB+OFA	0.34[c]	25-65[c]	5.5-6.5	
Lawrence 5, KS	400	U.S. MW	Baseline	0.43-0.5	NA	0.4	Thompson
		Bituminous	LNB+OFA	0.24-0.3	NA	0.3	1989
Valmont 5, CO	165	U.S. W. Bituminous	Baseline	0.66	30	1.6	Hunt 1991
			LNB+OFA	0.29-0.31	30	1.6	

[a]To convert to ppm @ 3% O_2, multiply by 750.
[b]No data available.
[c]Long-term test data.

Table 7-3. Summary of baseline/controlled CO and UBC data, coal-fired cyclone and turbo furnace boilers

Boiler ID	Capacity (MWe)	Coal Type	NO_x Control	NO_x (lb/MMBtu)[a]	CO (ppm @ 3% O_2)	UBC (%)	Reference
Cyclone Units:							
Nelson Dewey 2, WI	100	U.S. Bituminous	Baseline	0.81	90	NA[b]	Newell 1992
			Coal reburn	0.36	90	NA	
Niles I, OH	108	U.S. E. Bituminous	Baseline	0.94	30	1.39	Booth 1991
			N.G. reburn	0.37	35	1.15	Brown 1992
Turbo Furnace:							
Wabash 5, IN	105	NA	Baseline	0.85	NA	10	Penterson
			LNB	0.45	NA	3.5	1991

[a]To convert to ppm @ 3% O_2, multiply by 750.
[b]No data available.

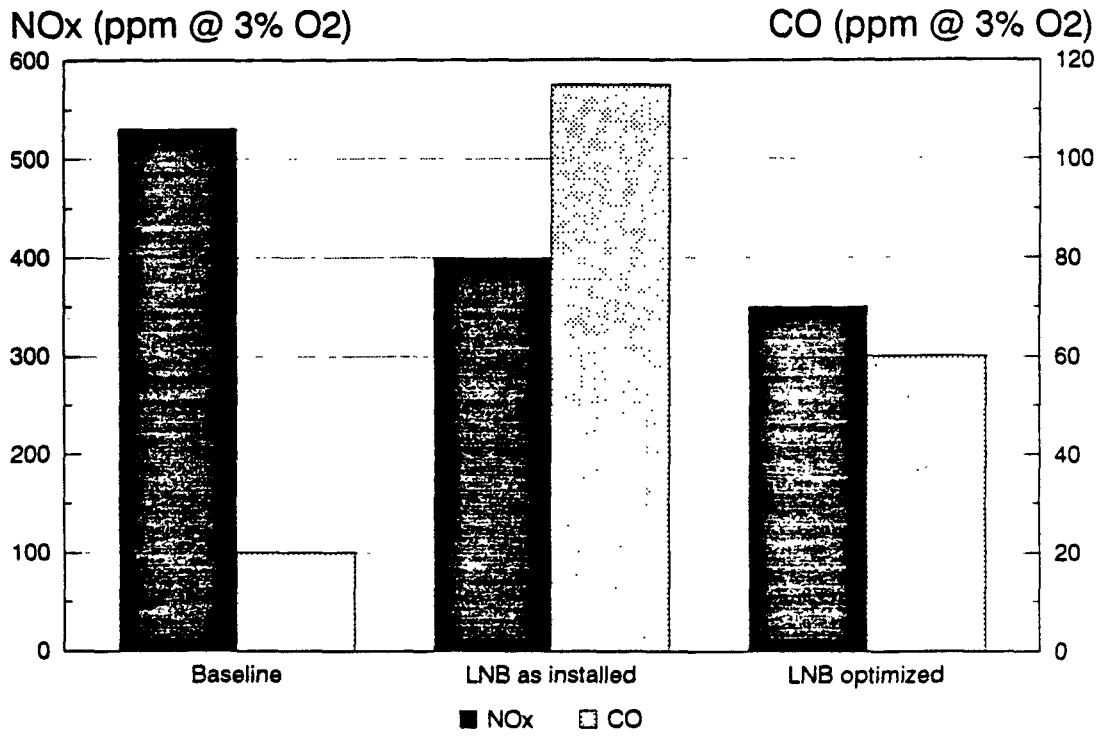


Figure 7-1. NO_x and CO emissions at full load, Edgewater Unit 4

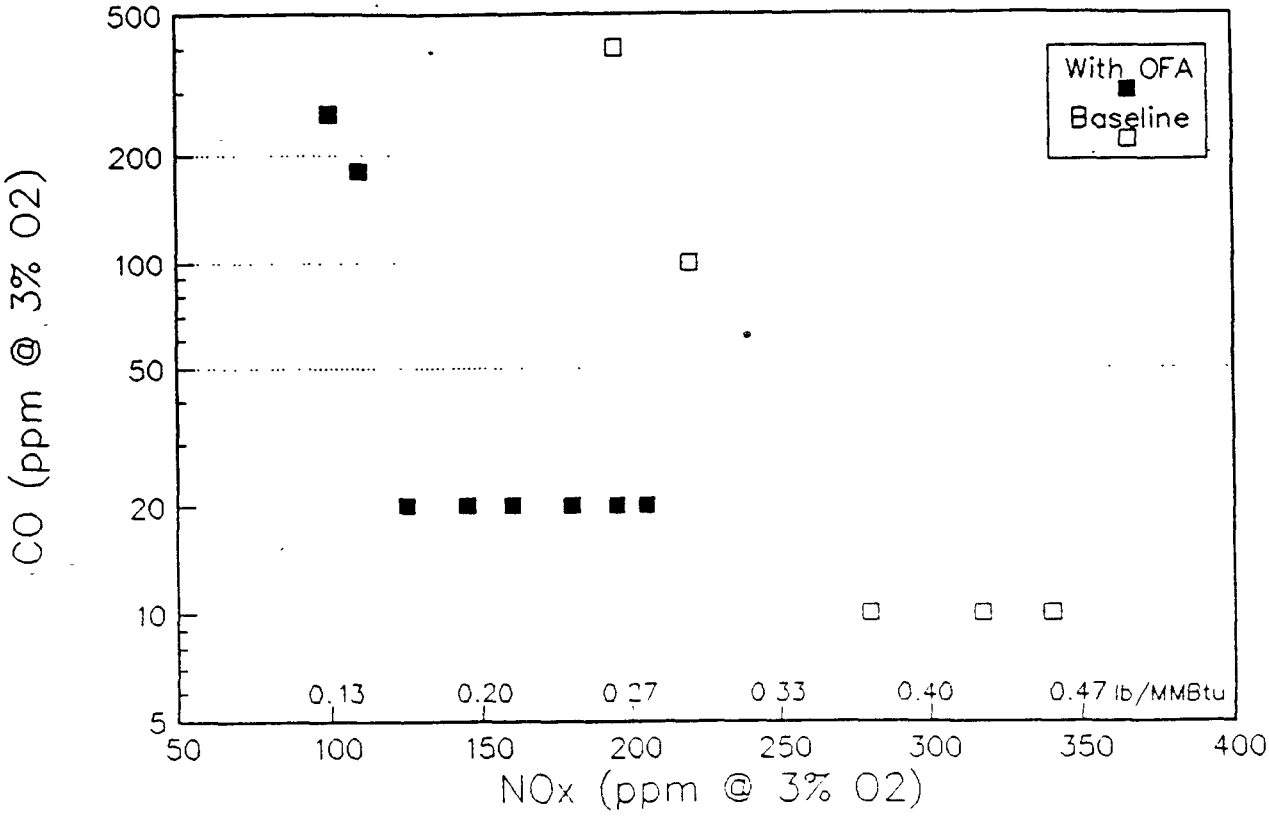


Figure 7-2. CO versus NO_x, 600 MWe wall-fired boiler with OFA, firing German brown coal

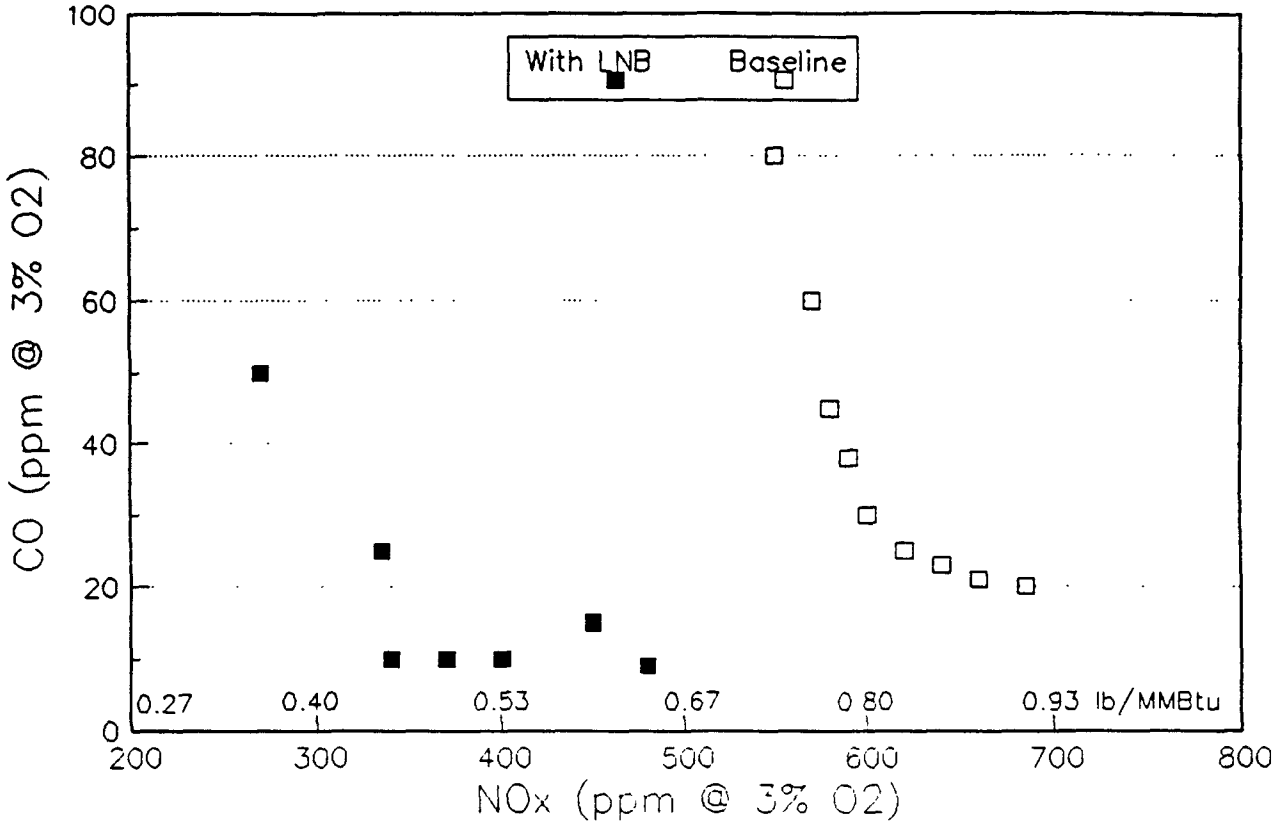


Figure 7-3. CO versus NO_x, NEI-ICL, 500 MWe wall-fired boiler with/without LNB

of both the LNB and OFA resulted in a total NO_x reduction of 65 percent; however, CO increased by 150 percent (Vatsky, 1989).

Six of the tangential-fired boilers listed in Table 7-2 were retrofitted with combined LNB and OFA NO_x controls. Of the three units for which pre- and post-retrofit CO data were available, two experienced no change in CO as a result of adding NO_x controls, while the third experienced only a slight increase in CO. The units with unchanged CO both were fired on highly reactive western bituminous coal while the third unit, Plant Lansing Smith Unit 2, fired eastern bituminous coal with a lower volatile content (Hardman, 1992). CO was no higher than 65 ppm for this unit, under low-NO_x conditions. The data support the conclusion that the use of high volatile coals results in a lower tendency towards high CO emissions, relative to low volatile eastern coals.

The single tangential boiler with gas reburn controls, Hennepin Unit 1, experienced no adverse effect on CO emissions, even when 60-percent NO_x reduction was achieved (May 1992).

CO emissions for the two cyclone boilers in Table 7-3 did not increase much when reburn control technology was applied. For example, CO for Niles Unit 1 increased only 5 ppm when NO_x was reduced 60 percent. Meanwhile, at the 100 MW Nelson Dewey Unit 2, the furnace emitted 90 ppm CO during both pre- and post-retrofit tests. An NO_x reduction of 55 percent was achieved with coal reburn.

Additional examples that support the conclusion that CO emissions remain at low levels, following the retrofit of NO_x controls are provided by these additional cases. For example, Vado Ligure Unit 4 had CO emissions less than or equal to 8 ppm and Fusina Unit 2 reported a maximum CO level of 40 ppm after retrofit (Grusha, Tarli 1991). No baseline CO emission data were reported for these units. Valmont Unit 5 and Cherokee Unit 4 both emitted less than 30 ppm CO before and after retrofit, and Four Corners Unit 4 reported maximum CO emissions of 40 ppm. Thus, these units were able to achieve between 35 and 60 percent NO_x reduction while keeping CO emissions at or below 40 ppm. Corresponding NO_x levels for these units ranged from 210 to 300 ppm (0.28 to 0.4 lb/MMBtu). Valmont Unit 5 and Cherokee Unit 4, using LNB and OFAs, were able to maintain low CO levels by keeping the post-retrofit overall boiler oxygen concentration equal to baseline levels, while lowering the stoichiometric ratio in the main burner area (Hunt, 1991).

Little data are available on CO emissions resulting when flue gas treatment controls are used, in part because attention has focused on the issue of ammonia slip instead, which is a more important concern with urea- and ammonia-based controls. This concern was previously highlighted in Section 4.3. The use of urea injection did not appear to affect CO emissions to any measurable degree for the Kerr-McGee Argus Unit 26, a PC-fired 750,000 lb/hr tangential boiler. Average CO emissions before SNCR was applied were 11 ppm. When urea injection was used, NO_x levels decreased 33 percent to an average level of 135 ppm (0.18 lb/MMBtu), thereby meeting the NO_x emission standard for that unit, while CO emissions increased to only 17 ppm.

Table 7-4 shows levels of NO_x reduction at various CO emission levels for 10 of the boilers in Tables 7-1, 7-2, and 7-3. Data are given for situations when post-retrofit CO levels are similar to pre-retrofit levels. The highest reported post-retrofit CO levels are also listed with their corresponding NO_x levels. For all units, the NO_x reduction level at which post-retrofit CO emissions begin to increase above baseline levels ranged between 33 and 61 percent NO_x reduction.

In conclusion, baseline and controlled data on NO_x and CO emissions from existing coal-fired boilers appear to be very site-specific. Factors including load, coal characteristics, furnace design and operating conditions can influence the level of NO_x reduction without significant increases in CO emissions. Limited data reviewed, presented in Tables 7-1 through 7-4, suggest that, for some NO_x control techniques, CO levels can increase markedly as the NO_x reduction goal is increased beyond 50 percent. Additionally, the data suggest that the use of reactive western coals results in a lower tendency towards high CO emissions, relative to less reactive eastern coals.

7.1.2 Unburned Carbon

The amount of UBC in the flyash depends on several factors, including the physical and chemical coal characteristics in addition to burner/furnace operation. Coal reactivity and coal fineness are two of the most important coal characteristics which affect UBC levels in pulverized coal firing. Coals with high levels of volatile matter, that is, lignitic, subbituminous, or western bituminous coals, are generally much more reactive that coals with low percentages of volatile matter. High volatile content coals correspondingly show much lower levels of UBC and are relatively less sensitive to variations in the combustion environment such as changes in burner stoichiometry, firing rate, and excess air levels (Lewis, 1989; Grusha, 1991; Miyamae, 1987; Tanaka, 1987). Typically, lower NO_x levels are possible with higher reactive coals without significant penalties in combustion efficiency (Lewis, 1989; Narita, 1987; Offen, 1989). Most of the UBC data presented in this section are for units firing reactive or foreign coals. Only six units fired less reactive eastern bituminous coals.

Table 7-4. NO_x reduction at various CO emission levels, selected coal-fired boilers

Boiler/Burner	Baseline			Low NO_x Combustion								NO_x Control Type
				CO ≈ Baseline CO				Highest Given CO				
	NO_x (lb/MMBtu)	NO_x (ppm @ 3%O_2)	CO[a] (ppm @ 3%O_2)	NO_x (lb/MMBtu)	NO_x (ppm @ 3%O_2)	CO (ppm @ 3%O_2)	NO_x Red. (%)	NO_x (lb/MMBtu)	NO_x (ppm @ 3%O_2)	CO (ppm @ 3%O_2)	NO_x Red. (%)	
Wall Fired												
Edgewater 4, OH	0.71	530	20	0.37	280	60[c]	47	0.43	320	115	40	LNB
Four Corners 4, NM	1.27	950	40	0.50	375	40	61	0.50	375	40	61	LNB
NEI-ICL, U.K.	0.91	685	20	0.45	340	20	50	0.36	270	50	61	LNB
Pleasants 2, PA	0.95	710	60	0.41	310	40	56	0.33	250	100	65	LNB/OFA
RWE, Germany	0.37	280	10	0.17	125	20[c]	55	0.13	100	260	64	OFA
Vado Ligure, Italy	0.78	585	NA[b]	0.52	390	8	33	0.52	390	8	33	OFA
Tangential												
Cherokee 4, CO	0.53	400	<30	0.31	230	30	43	0.31	230	30	43	LNB/OFA
Fusina 2, Italy	0.67	500	NA[b]	0.30	225	40	55	0.30	225	40	55	LNB/OFA
Valmont 5, CO	0.66	495	<30	0.29	215	30	57	0.29	215	30	57	LNB/OFA
Cyclone												
Niles 1, OH	0.94	705	30	0.37	275	35	61	0.37	275	35	61	Reburn

[a]Lowest level reported.
[b]No baseline data available.
[c]Lowest CO under NO_x conditions was much different from baseline.

Figure 7-4 depicts NO_x versus UBC levels for three of the wall-fired boilers in Table 7-1; all showing increased UBC with decreasing NO_x. Using a LNB, NO_x emissions from Drax Unit 6 were reduced 50 percent to approximately 400 ppm (0.53 lb/MMBtu) before UBC levels increased above baseline values. Data reported for Inkoo Unit 4 showed an increase in UBC after retrofit with combustion control. UBC levels increased from 3 to approximately 6 percent when NO_x was reduced from 750 to 330 ppm (1.0 to 0.44 lb/MMBtu). For Edgewater 4 UBC increased only slightly from 2 to 3 percent at 40 percent NO_x reduction. When an additional 7 percent NO_x was reduced, however, UBC rose markedly to 6 percent. Table 7-5 summarizes UBC in flyash data for selected boilers whose UBC levels changed after retrofit with NO_x controls. In general, post-retrofit UBC levels for the wall-fired boilers did not increase markedly until greater than 40 percent NO_x reduction was achieved.

A number of the boilers listed in Table 7-1 through 7-3 showed no increase in UBC when NO_x controls were used, even when boiler excess air levels were lowered. The majority of these units were fired on highly reactive western, subbituminous, or foreign coals. When less reactive coals were used with retrofit NO_x controls, UBC levels tend to increase with the lowering of burner stoichiometries to reduce NO_x (Offen, 1989). For Eggborough Unit 2, UBC was much more sensitive to burner stoichiometry when LNB was used. Prior to the retrofit, under baseline conditions, lowering the excess air to reduce NO_x increased UBC by 1 percentage point for every 100 ppm (0.13 lb/MMBtu) NO_x reduction. After LNB retrofit, lowering excess air caused an increase of 4 percentage points of UBC for every 100 ppm NO_x reduction. This trend was also noted for Vado Ligure Unit 4, the boiler tested by NEI-ICL, and Maas Unit 5. Thus, when lowering excess air, UBC increases at a faster rate under low-NO_x conditions compared to operation with the regular burner.

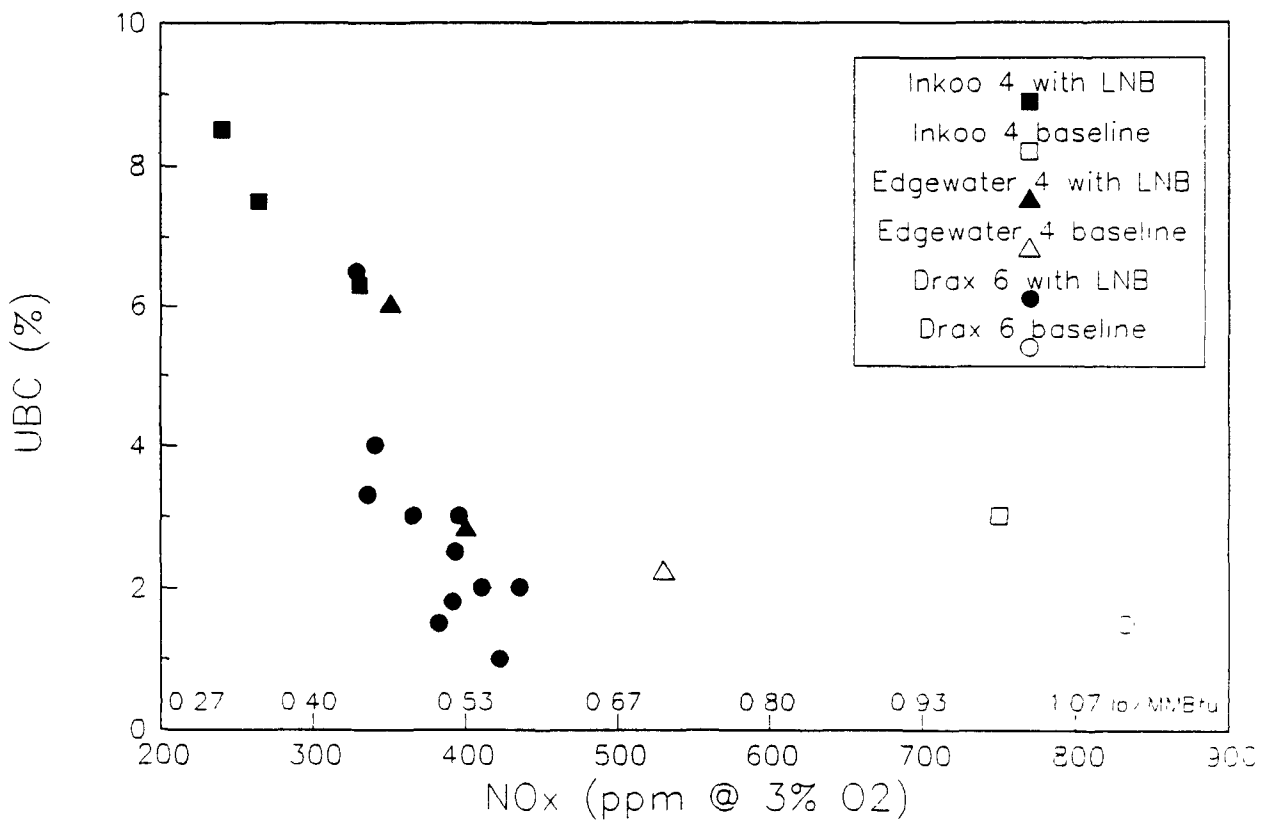


Figure 7-4. NO_x versus UBC, wall-fired boilers with LNB

Table 7-5. NO_x reduction at various UBC levels for coal-fired boilers at full load

Boiler/Burner	Baseline			Low NO_x Combustion							
				UBC ≈ Baseline UBC				Highest Given UBC			
	NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	UBC[a] (%)	NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	UBC (%)	NO_x Red. (%)	NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	UBC (%)	NO_x Red. (%)
Wall Fired											
Drax 6, U.K.	1.11	832	1.0	0.56	422	1.0	49	0.44	328	6.5	61
Edgewater 4, OH	0.71	530	2.2	0.42	317	2.8	40	0.37	281	6.0	47
Eggborough 2, U.K	0.84	530	1.2	0.6	450	3.0	29	0.45	340	7.2	46
Hammond 4, GA	1.20	900	5.2	0.62	470	8.0	48	0.54	405	11	55
Inkoo 4, Finland	1.03	770	3.0	0.44	330	6.3	57	0.32	240	8.5	69
Maas 5, Netherlands	0.69	515	0.6	0.42	312	0.7	39	0.4	300	1.8	42
NEI-ICL, U.K.	0.91	685	2.1	0.6	450	1.8	34	0.36	270	7.0	61
Vado Ligure, Italy	0.93	700	5 5	0 63	472	7.7	33	0.52	390	12	44
Tangential											
Fusina 2, Italy	0 67	500	7.0	0.55	410	8.5	18	0.3	225	10.3	55

[a]Lowest level reported.

Another important coal characteristic which can influence the amount of unburned carbon in flyash is particle fineness. Utility boilers generally pulverize coal to about 70 percent through 200 mesh. Although this is adequate for baseline operation, the retrofit of combustion NO_x controls may necessitate an increase in coal fineness. As discussed in Section 4, this can be accomplished by modification of the classifiers on existing mills or replacement of the mills with larger capacity and more efficient designs available today. The recent retrofit of Hammond Unit 4 with OFA ports and LNB has shown that relatively low coal fineness (63 to 67 percent through 200 mesh), coupled with NO_x reductions in the order of 50 percent, can result in unacceptably high levels of UBC. In this retrofit, UBC levels reached 11 percent from a baseline of 5.2 percent at full boiler load (Sorge, 1992).

Increasing the fineness of the pulverized coal often results in more complete combustion and lower UBC levels (Makino, 1989; Trivett, 1991, Ghiribelli, 1992). A study of the effects of particle fineness of seven different coals on combustion efficiency showed that UBC levels increase considerably when the particle size is increased; the study also showed that NO_x emissions increase with increased particle size. It was determined that smaller particles allow for increased staging and hence lower NO_x (Kinoshita, 1989). Thus, reductions in burner efficiency due to the addition of low NO_x controls can be somewhat counterbalanced by increasing the fineness of the coal. For example, increasing the mill fineness reduced UBC to acceptable values (6 to 8 percent) for all of the coals tested in Fusina Unit 2 (Tarli, 1991).

7.2 CO EMISSIONS FROM NATURAL GAS-FIRED UTILITY BOILERS

Figure 7-5 shows CO emissions as a function of NO_x levels for two natural gas-fired boilers operating with combustion modification NO_x controls. CO data for these and for seven other boilers are also given in Table 7-6. NO_x emission ranges are wide and dependent on the specific boiler. SCE's Redondo Unit 8 and Alamitos Unit 6 emitted NO_x at much lower levels than any other boiler previously described, under lowest-NO_x operating modes. CO emissions, however, for all but the South Bay Unit 1 were below 100 ppm (0.12 lb/MMBtu) except at maximum NO_x reduction conditions.

Data from Fusina Unit 2 exhibited a very gradual increase in CO emissions until NO_x fell below 100 ppm, as CO emissions remained in the range of 50 ppm. At approximately 65 percent NO_x reduction from baseline, corresponding to 60 ppm NO_x (0.07 lb/MMBtu), CO emissions were twice the baseline level. Emissions from this boiler were dependent on the firing zone stoichiometry. As the stoichiometry was reduced by the utilization of staged combustion, NO_x decreased by a maximum 70 percent; CO at this NO_x level was 175 ppm, the highest level throughout all testing (Grusha, 1991).

Rossano Unit 4 displayed a greater CO increase compared to Fusina Unit 2. The rate of CO increase divided by the rate of NO_x decrease was, in fact, highest when NO_x control—in this case, BOOS—was used. With 12 of 18 burners in service, CO increased by 5.8 ppm for every 1 ppm NO_x reduction; in comparison, with all burners in service (ABIS), CO increased by only 3.4 ppm for every 1 ppm NO_x reduction as excess air was reduced to optimize NO_x reduction performance (Benanti, 1989).

Figure 7-6 shows the relationship between CO and excess oxygen levels for SCE's Ormond Beach Unit 2, an 800 MW wall-fired boiler that was retrofitted with LNB. Data is depicted for pre- and post-retrofit O.S. and ABIS firing modes. O.S. firing in this case was achieved by taking selected BOOS. A comparison of the pre- and post-retrofit O.S. curves shows that in order to keep post-retrofit CO equal to pre-retrofit levels, the excess oxygen had to be increased. For example,

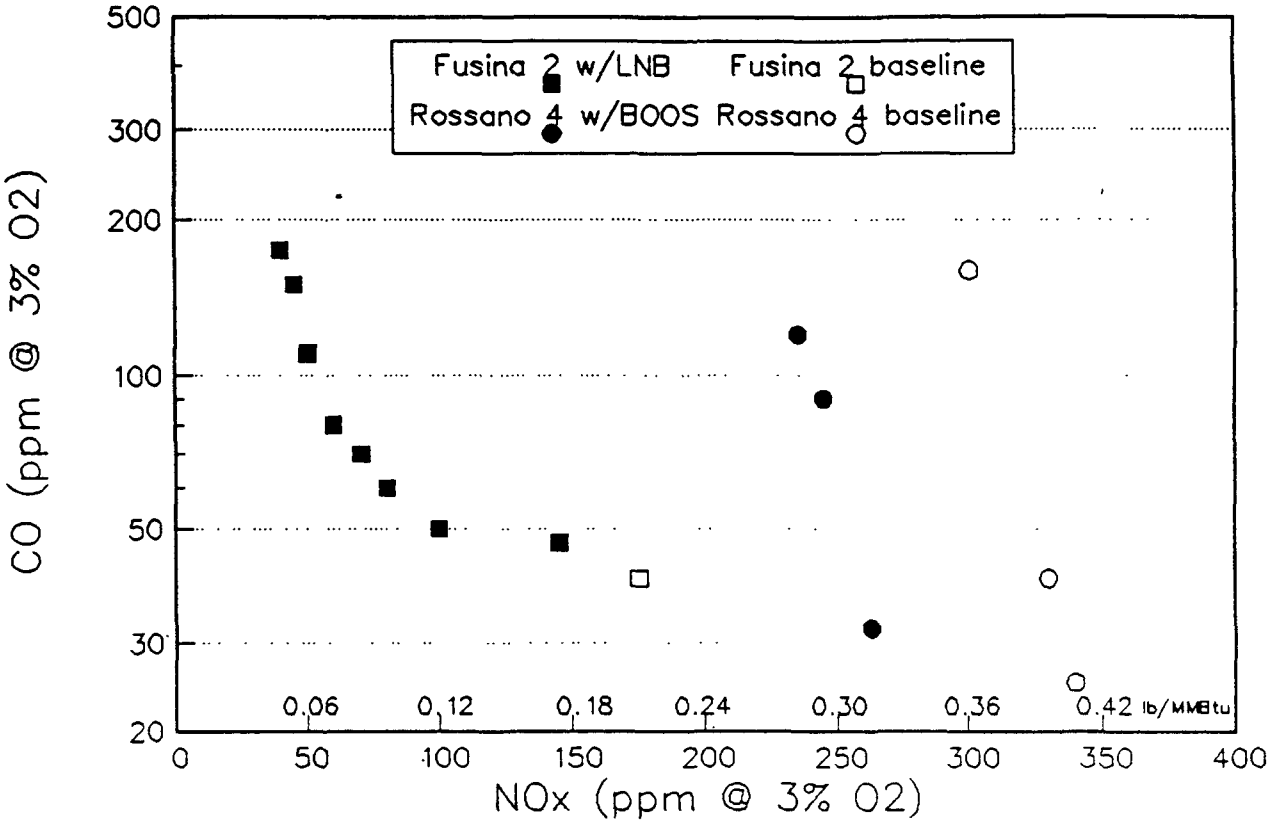


Figure 7-5. CO versus NO_x, natural gas-fired boilers

Table 7-6. Summary of CO data for natural gas-fired boilers

Boiler/Burner	Baseline			With NO_x Control			NO_x Control Type	Reference
	NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	CO (ppm @ 3% O_2)	NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	CO (ppm @ 3% O_2)		
Wall Fired								
Alamitos 5, CA[a]	0.03-0 13	25-112	0-700	0.02-0.08	16-65	0-330	LNB/BOOS	Bayard De Volo 1991
Arzberg 6, Germany	0 36	300	NA	0.06	50	15	LNB	Lisauskas 1991
NEPCO LNB Project	NA	NA	NA	0.06-0.07	54-60	12	LNB	Afonso 1991
Redondo 8, CA	0 10	87	100	0.07	56	90	BOOS	McDannel 1991
B&W XCL Burner[b,d]	0 06-0 13	50-110	NA	0 04-0.09	33-74	35-46	LNB	LaRue 1989
Rossano 4, Italy[c]	0 36-0 41	300-340	25-160	0.26-0.31	220-263	32-280	BOOS	Benanti 1989
Sermide 3, Italy	0.40	333	NA	0.1	83	32	BOOS	Tarli 1991
South Bay 1, CA[c]	0.20	170	250	0.13	110	800	Bias firing	Quartucy 1987
South Bay 1, CO[c]	0.20	170	250	0.13	113	3700	BOOS	Quartucy 1987
Tangential								
Fusina 2, Italy[b]	0.21	175	40	0 05-0.17	40-145	47-175	LNB	Grusha 1991

[a]BOOS and FGR were in use prior to retrofit with LNB.
[b]Long-term testing.
[c]Short-term testing.
[d]Results of the B&W XCL burner tested at the Riley Combustion Research Facility.

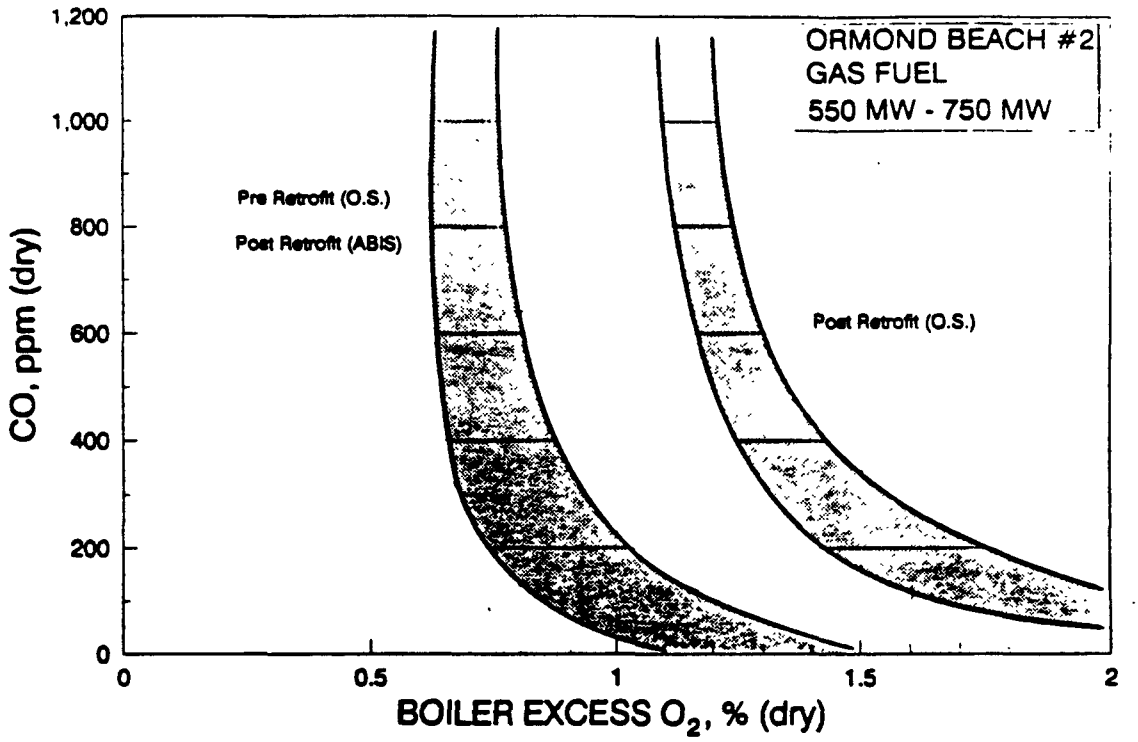


Figure 7-6. Pre- and post-retrofit CO emissions versus excess O_2—SCE Ormond Beach Unit 2 (Bayard de Volo, 1991) (O.S. = Off Stoichiometric; ABIS — All Burners in Service)

when pre-retrofit CO was 200 ppm, excess oxygen was roughly between 0.75 and 1 percent. Under post-retrofit O.S. firing, excess oxygen had to be increased to bottom 1.5 and 1.75 percent in order to keep CO at 200 ppm. This increase is excess oxygen reduced the amount of NO_x reduction achieved by the LNB (Bayard de Volo, 1991).

In the case of Alamitos Unit 6, a 480-MW wall-fired boiler outfitted with the same LNB as Ormond Beach 2, the minimum allowable excess oxygen level at which acceptable CO emissions were maintained was lower after retrofit (Figure 7-7). This reduction in minimum allowable excess air did not follow the more typical trend that was displayed by Ormond Beach Unit 2. Figure 7-7 shows the relationship between CO and excess O_2. Under post-retrofit O.S. (BOOS) firing mode, Alamitos Unit 6 was able to operate on lower excess oxygen, keeping CO emissions the same as pre-retrofit levels. The CO/O_2 performance of Alamitos Unit 6 was attributed partly to more uniform air and fuel flow in the firing zone, which was achieved by modifying the boiler windbox and by balancing the burner fuel and air flows during shakedown testing. Similar windbox modifications had been made to the Ormond Beach Unit, but the results were as described above, with little improvement in CO/O_2 performance. SCE could not explain the large variance between the two boilers' performance (Bayard de Volo, 1991). It is probable that the differences in boiler size and design contributed to these results. This demonstrates that there may be exceptions to the general trends that can be seen in boiler performance, and that emissions performance is very boiler-specific and may depend on other factors besides the actual application of low-NO_x controls.

This is indeed the case with Redondo Unit 8 and South Bay Unit 1. Taking Burner 6 out of service from Redondo Unit 8 resulted in a 36 percent reduction in NO_x without adversely affecting CO. The explanation for this is that Burner 6 south had been "starved" for air, resulting in lower O_2 and higher CO levels in the south side of the boiler when Burner 6 was in service. The

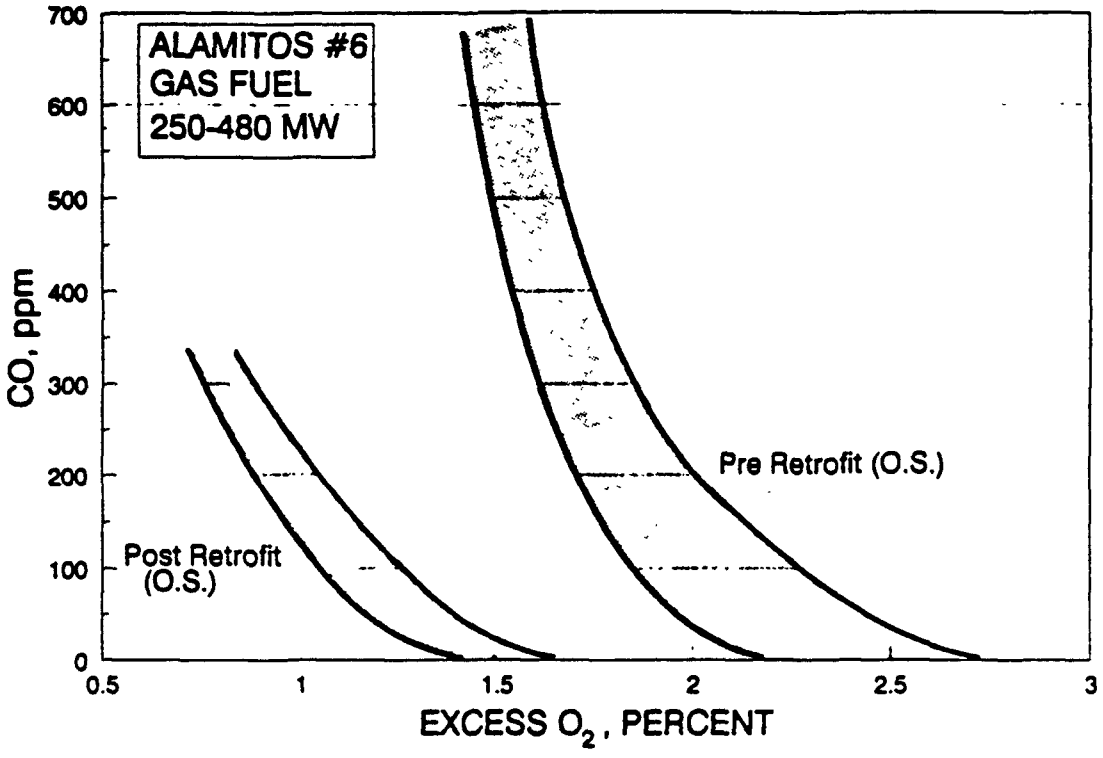


Figure 7-7. Pre- and post-retrofit CO emissions versus excess O_2—SCE Alamitos Unit 6 (Bayard de Volo, 1991) (O.S. = Off Stoichiometric)

removal of Burner 6 thus improved the overall combustion air balance between the north and south sides, resulting in lower CO (McDannel, 1991). This was much the case with South Bay Unit 1, where it was determined that four of the eight burners were starved for air; this poor air/fuel distribution was due to nonuniform fuel orifice sizes in the burner rings. BOOS operation resulted in an exponential increase in CO emissions to levels greater than 2000 ppm. The use of the fuel biasing resulted in a lower CO emission level, yet this was still more than three times as high as the baseline level of 250 ppm (Quartucy, 1987).

Three other boilers or burners in Table 7-6—Arzberg Unit 6, the low-NO_x burner tested for New England Power Company (NEPCO) which simulates Brayton Point and Salem Harbor Units 4, and Sermide Unit 3—emitted no more than 32 ppm CO during low NO_x operation. Corresponding NO_x emissions were also quite low, ranging between 50 and 83 ppm (0.06 to 0.1 lb/MMBtu). The fourth unit, the low-NO_x B&W XCL burner evaluated at the Riley test facility, also had NO_x emissions of less than 80 ppm (0.1 lb/MMBtu), but had a higher level of CO averaging 40 ppm. These relatively low CO emission levels suggest that for these units, the effect of adding NO_x controls on CO emissions is not great.

Table 7-7 summarizes NO_x emission levels and NO_x reduction at various CO emission levels. NO_x reductions for wall-firing ranged from 23 to 83 percent at the point where CO emissions begin to increase above baseline levels, while for the tangential-fired Fusina Unit 2, this point corresponded to 17 percent NO_x reduction. High CO levels with low NO_x reduction efficiencies are more likely when the initial NO_x levels is low, as is the case for many Southern California boilers. Otherwise, significant NO_x reductions are possible from gas-fired boilers without

Table 7-7. NO_x reduction at various CO emission levels, selected natural gas-fired boilers

Boiler/Burner	Baseline			Low NO_x Combustion								NO_x Control Type
				CO ≈ Baseline CO				Highest Given CO				
	NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	CO[a] (ppm @ 3% O_2)	NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	CO (ppm @ 3% O_2)	NO_x Red. %	NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	CO (ppm @ 3% O_2)	NO_x Red. %	
Wall Fired												
Arzberg 6, Germany	0.36	300	NA[b]	0.06	50	15	83	0.06	50	15	83	LNB
NEPCO LNB Project	NA[b]	NA[b]	NA[b]	0.06	54	12	NA	0.06	54	12	NA	LNB
Redondo 8, CA	0 10	87	100	0.07	56	90	36	0.07	56	90	36	BOOS
B&W XCL Burner	0.10	80	NA[b]	0.04	33	36	59	0.08	65	46	19	LNB
Rossano 4, Italy	0.41	340	25	0.31	263	32	23	0.26	220	280	35	BOOS
Sermide 3, Italy	0.40	333	NA[b]	0.10	83	32	75	0.10	83	32	75	BOOS
Tangential												
Fusina 2, Italy	0.21	175	40	0.17	145	47	17	0.05	40	175	77	LNB

[a]Lowest level reported.
[b]No baseline data available.

an increase in CO emissions. CO emissions range from gas-fired boilers evaluated in this study showed a range of 12 to 90 ppm at combustion-controlled NO_x emission levels in the range of 0.06 to 0.31 lb/MMBtu.

7.3 CO EMISSIONS FROM OIL-FIRED UTILITY BOILERS

CO and NO_x emission data for 12 oil-fired boilers or burners are given in Table 7-8. For those units with both pre- and post-retrofit data available, these data are also presented graphically in Figure 7-8. It is apparent that CO emission levels for most of these boilers tended to be no higher than 50 ppm prior to use of NO_x controls. Only Monfalcone Unit 4 reported baseline CO emissions which were greater.

The data in Table 7-8 and in Figure 7-8 show little or no increases in CO when NO_x controls were used, unless absolute minimum NO_x levels were pursued. As discussed below, 26 to 57 percent NO_x reduction was achieved from the eight wall-fired boilers with no increase in CO.

In order to maintain low CO emissions, higher excess oxygen is often necessary when low-NO_x combustion controls are used. Thus, operational flexibility with excess air is reduced at low-NO_x conditions. Monfalcone Unit 4 illustrates this trend. Prior to retrofit with LNB, NO_x could be reduced 30 percent using low excess oxygen while keeping CO emissions below 70 ppm. In order to maintain the same level of CO after the LNB retrofit, the excess air level had to be raised, limiting low excess air's NO_x reduction contribution to only 19 percent (Tarli, 1991). The LNB provided the remainder of the overall 51 percent post-retrofit NO_x reduction. In Figure 7-8, the steeper rise in CO with small reduction in NO_x is more evident in the post-retrofit case than in the baseline case. Overall, Figure 7-8 shows that for the four boilers post-retrofit CO emissions were kept at roughly the same levels as pre-retrofit emissions.

Table 7-9 summarizes NO_x reductions and emission levels when post-retrofit CO emissions were roughly the same as pre-retrofit levels. For the eight wall-fired boilers, CO ranged from 20 to 67 ppm at this point. Corresponding NO_x reduction levels ranged between 26 and 57 percent, meaning that this range of NO_x reduction was attained on these boilers without an increase in CO emissions from baseline levels. This NO_x range is fairly consistent with the 33 to 60 percent range for coal-fired boilers discussed earlier.

In some cases where oil-fired boilers were retrofitted with NO_x controls, opacity reaches unacceptably high levels before CO emissions do. Increased stack opacity is indicative of higher soot emissions, which also contributes to higher particulate loadings and possibly higher air toxic emissions as well. These opacity levels thus act as the "trigger" for the maximum NO_x reduction that should be pursued. Opacity levels are generally related to NO_x emissions in much the same way as CO emissions, that is, as excess oxygen is decreased to lower NO_x, less complete combustion occurs, resulting in higher levels of opacity. Lowering NO_x is not the only cause of high opacity, however. Opacity is also dependent on fuel oil characteristics such as fuel grade (distillate versus residual) and mean droplet size (atomization efficiency).

This tradeoff between NO_x and opacity is a fundamental feature of the low-NO_x system in use at Hawaiian Electric Company's (HECO) Kahe Unit 6, particularly when firing heavy oil. Figure 7-9 gives a historical summary of NO_x and opacity levels for this 146 MW wall-fired boiler. Initially, between 1981 and 1988, the unit had been operating with FGR and BOOS to satisfy NO_x emission requirements; NO_x and opacity levels were 219 ppm (0.28 lb/MMBtu) and 6 percent, respectively (left most part of Figure 7-9). After retrofit with a LNB—known as the PG-DRB burner— and a front and rear wall OFA system, NO_x was reduced on average by 29 percent, with

Table 7-8. Summary of CO data for oil-fired boilers

Boiler/Burner	Oil Type	Baseline			With NO_x Control			NO_x Control Type	Reference
		NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	CO (ppm @ 3% O_2)	NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	CO (ppm @ 3% O_2)		
Wall Fired									
Arzberg 6, Germany	Light	NA	NA	NA	0.09	75	<25	LNB	Lisauskas 1991
B&W XCL Burner[a]	Heavy	0.25-0.27	200-210	NA	0.11-0.15	88-118	38-46	LNB	LaRue 1989
Florida P&L	Heavy	0.54-0.63	430-500	43-1110	0.20-0.27	155-215	40-1180	Reburn	Chen 1989
Monfalcone Unit 2, Italy	Heavy	0.62	485	26	0.25-0.30	200-235	25-35	LNB	Benanti 1992
Monfalcone Unit 4, Italy	Heavy	0.46-0.66	365-525	20-61	0.33-0.40	258-317	20-72	LNB	Tarli 1991
NEPCO LNB Project	Heavy	0.28	220	48	0.13-0.29	100-230	38-43	LNB	Afonso 1991
Rossano 4, Italy		0.48	377	NA	0.33	263	67	BOOS	Tarli 1991
Salem Harbor 4, MA	Heavy	NA	NA	NA	0.34	270	73	LNB/BOOS	Afonso 1992
Vartan PS, Sweden	Heavy	NA	NA	NA	0.18	140	<40	LNB	Lisauskas 1991
Zink Furnace 3, OK	Heavy	NA	NA	NA	0.30-0.32	234-250	0-50	LNB	Gerdes 1989
Tangential									
Fusina 2, Italy[b]	Heavy	0.30-0 32	240-250	20-25	0.11-0.16	90-125	25-316	LNB	Grusha 1991
Santa Gilla 2, Italy	Heavy	0 24-0.30	190-240	10-40	0.15-0.25	120-200	5-80	OFA	DeMichelle 1992
	Heavy	0.24-0.30	190-240	10-40	0.10-0.13	80-100	5-70	Propane reburn	

[a]Long-term testing.
[b]Short-term testing

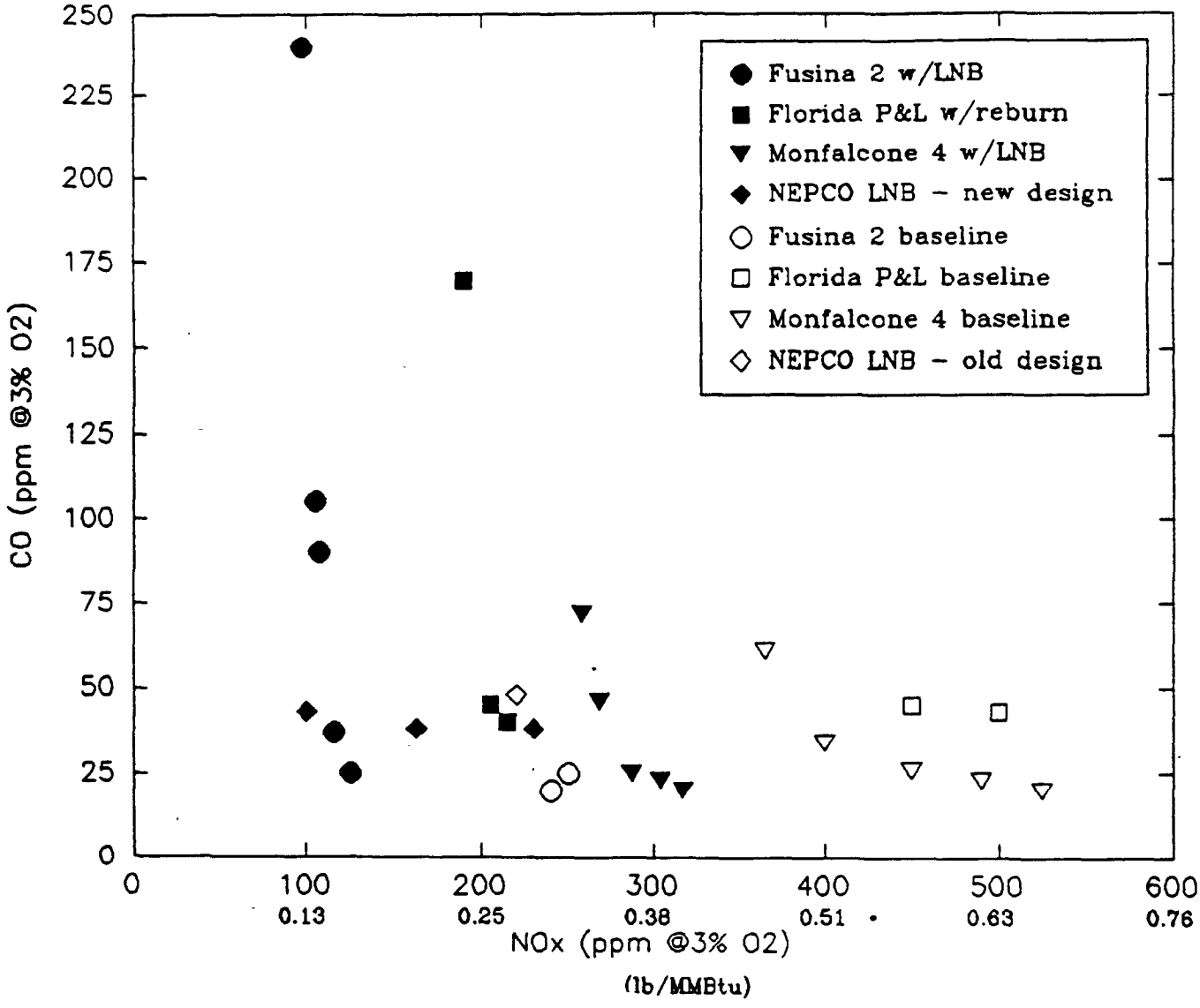


Figure 7-8. NO_x versus CO emissions—oil-fired boilers

Table 7-9. NO_x reduction at various CO emission levels, selected oil-fired boilers

Boiler/Burner	Fuel Type	Baseline			Low NO_x Combustion								NO_x Control Type
					CO ≈ Baseline CO				Highest Given CO				
		NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	CO[a] (ppm @ 3% O_2)	NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	CO (ppm @ 3% O_2)	NO_x Red. %	NO_x (lb/MMBtu)	NO_x (ppm @ 3% O_2)	CO (ppm @ 3% O_2)	NO_x Red. %	
Wall Fired													
Arzberg 6, Germany	Light	NA[b]	NA[b]	NA[b]	0.09	75	25	NA	0.09	75	25	NA	LNB
Florida P&L	Heavy	0.63	500	43	0.27	215	40	57	0.20	155	1180	69	Reburn
Monfalcone 4, Italy	Heavy	0.66	525	20	0.40	317	20	40	0.33	258	72	51	LNB
NEPCO LNB Project	Heavy	0.28	220	48	0.21	163	26	26	0.13	100	43	55	LNB
B&W XCL Burner	Heavy	0 26	205	NA[b]	0.15	118	38	42	0.11	88	46	57	LNB
Rossano 4, Italy		0.48	377	NA[b]	0.33	263	67	30	0.33	263	67	30	BOOS
Vartan PS, Sweden	Heavy	NA[b]	NA[b]	NA[b]	0.18	140	40	NA	0.18	140	40	NA	LNB
Zink Furnace 3, OK	Heavy	NA[b]	NA[b]	NA[b]	0.30	240	50	NA	0.30	240	50	NA	LNB
Tangential													
Fusina 2, Italy	Heavy	0.30	240	20	0.16	125	25	48	0.11	90	316	63	LNB

[a]Lowest level reported.
[b]No baseline data available.

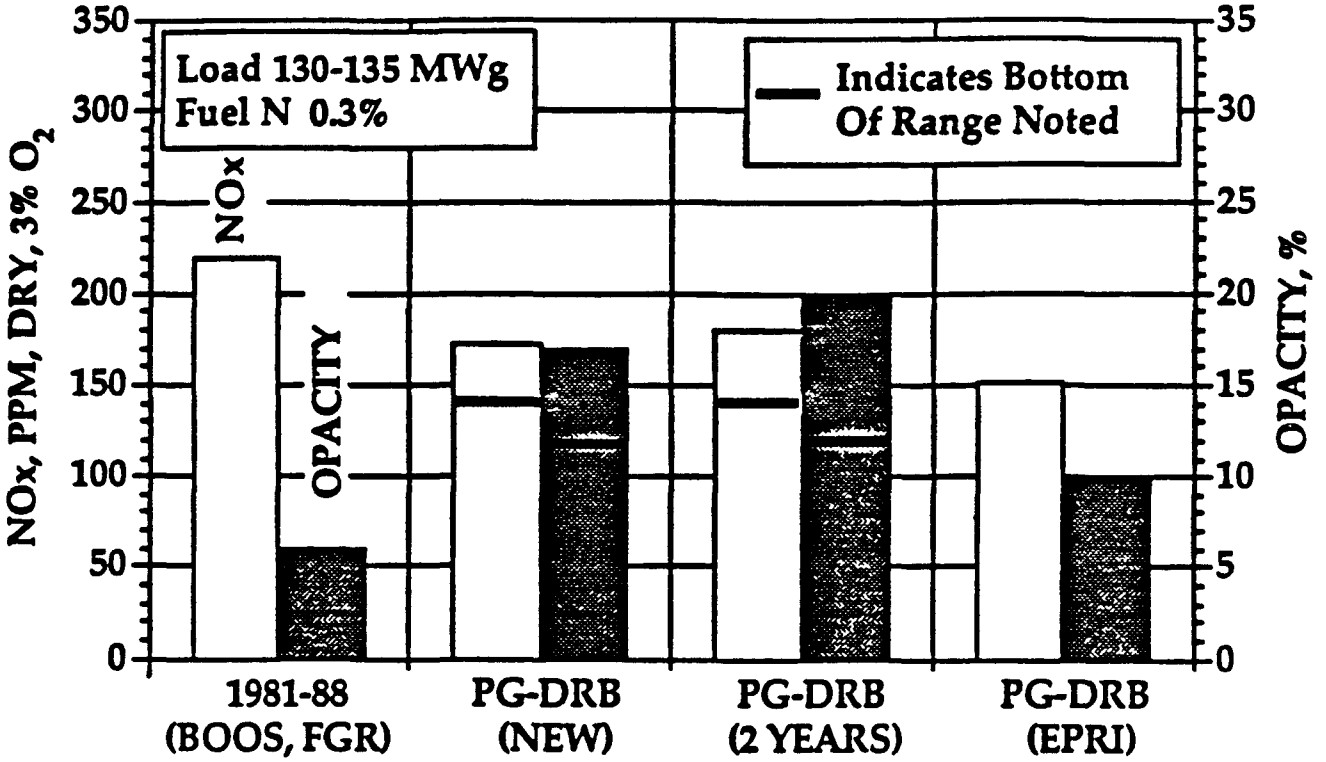


Figure 7-9. Historical summary of Kahe 6 NO_x and opacity (Kerho, 1991)
(Note: to convert ppm to lb/MMBtu divide by 790)

a range in controlled levels from 141 to 172 ppm (0.18 to 0.22 lb/MMBtu, second set of bars in Figure 7-9). At the same time, opacity levels more than doubled, increasing to between 12 and 17 percent. These ranges in NO_x or opacity are denoted by horizontal lines in the bars of Figure 7-8. Two years later, performance had degraded somewhat, with NO_x emissions being as high as 180 ppm (0.23 lb/MMBtu) and opacity levels reaching 20 percent (third set of bars in Figure 7-9). To reduce opacity levels, additional modifications were then made to the boiler under a program jointly sponsored by the Electric Power Research Institute (EPRI) and HECO (fourth set of bars in Figure 7-9). New fuel atomizers were installed to reduce the size of the oil droplets—smaller droplets burn out more completely, lowering the opacity—and the fuel and air flows to the burners were balanced. As a result of these changes, NO_x emissions were reduced to 152 ppm (0.19 lb/MMBtu) and opacity levels were lowered to 10 percent (Kerho, 1991).

7.4 HYDROCARBON EMISSIONS

THC emission test data are not commonly available for utility boilers. Since high CO, UBC, and opacity levels precede THC emissions (Radak, 1991), monitoring of THC emissions is not usually a part of the retrofit program. Table 7-10 summarizes the limited THC data collected as part of this study for three boilers with NO_x controls and seven units without controls. THC

Table 7-10. Summary of total hydrocarbon (THC) emission data

Boiler Unit	Fuel	THC Data (measured as hexane)	NO_x Levels, ppm @ 3% O_2 (lb/MMBtu)	Reference
Boilers with NO_x Controls:				
Alamitos 6, CA Ormond Beach 2, CA	Natural gas	No increase in THC under lowest NO_x operating conditions compared to pre-retrofit	16-90 (0.02-0.11)	Bayard de Volo 1991
Alamitos 6, CA Ormond Beach 2, CA	Oil	No increase in solid carbon or condensible hydrocarbon under lowest NO_x conditions	90-150 (0.11-0.18)	Bayard de Volo 1991
Niles 1, OH	Coal	Negligible THC gaseous emissions	275 (0.37)	Booth 1991
Uncontrolled Boilers:				
Crist 6	Coal	0.32 ppm (avg.)	290-681 (0.39-0.91)	EPA 1974
Harllee Branch 3	Coal	0.56 ppm (avg.)	148-747 (0.20-0.99)	EPA 1974
Naughton 3	Coal	0.46 ppm (avg.)	169-569 (0.23-0.76)	EPA 1974
SCE Boiler	Oil	1.75 ppm	NA[a]	Taback 1978
Widows Creek 6	Coal	0.39 ppm (avg.)	290-681 (0.39-0.91)	EPA 1974
Wood River 1, IL	Oil	0.32 ppm	63-95 (0.08-0.12)	EPA 1977
Wood River 4, IL	Coal	0.24 ppm	465-490 (0.62-0.65)	EPA 1977

[a]NA = No data available.

emissions from these utility boilers were very low, ranging from negligible levels to less than 2 ppm (THC as hexane), independent of fuel or boiler type.

For example, SCE reported an increase in THC emissions under the lowest NO_x operating conditions (off stoichiometric firing, low excess air, high FGR), compared to pre-retrofit conditions, for both Alamitos Unit 6 and Ormond Beach Unit 2 when firing natural gas. There was also "no increase in solid carbon or condensible hydrocarbons under lowest NO_x conditions" when firing oil (Bayard de Volo, 1991). Niles Unit 1, operating on coal, reported "negligible gaseous THC emissions" (Booth, 1991). These three boilers illustrate that THC emissions from utility boilers tend to be very low under low NO_x conditions, regardless of the fuel used.

A short-term test of a SCE boiler firing No. 6 residual oil measured THC emissions of less than 2 ppm, measured as hexane. The low level of hydrocarbon in this test was attributed to the relatively long residence time of the combustion gases in the boiler, allowing ample time for more complete combustion (Taback, 1978). Data are also provided on two boilers tested in the late 1970s at Illinois Power's Wood River Power Plant. Short-term tests were conducted using oil and coal. THC emissions were found to be less than 1 ppm for both fuels (EPA, 1977). Similar THC emissions levels were measured at the remaining boilers, in Table 7-8, all of which were fired on coal.

Typically, THC emissions from oil-fired utility boilers are on the order of 0.005 lb/MMBtu, while for natural gas-fired boilers, THC emissions are typically 1×10^{-5} lb/MMBtu (Taback, 1978). Three test programs on utility boilers measured hydrocarbon emissions less than 1 ppm in virtually all tests, for both baseline and low NO_x operation. It was concluded that THC emissions were relatively unaffected by imposing NO_x combustion controls on large utility boilers (EPA, 1980).

7.5 SUMMARY AND CONCLUSIONS

CO emissions data for 25 coal-fired, 9 natural gas-fueled, and 12 oil-fired boilers were examined in this study. These data are summarized in Table 7-11. Although the listed NO_x reduction ranges are very wide in general, when NO_x combustion controls were used, there was relatively little increase in CO emissions until 40 to 50 percent NO_x reduction—referenced to baseline levels—was achieved, beyond which CO levels begin to increase rapidly. The magnitude of this increase varies widely from boiler to boiler, and is affected by fuel type, furnace volume, heat release rate, burner configuration, NO_x control technique, uncontrolled NO_x level and control target, and fuel/oxygen balance, as well as the condition of existing boiler equipment.

For PC wall-fired boilers, firing bituminous coal, CO was found to increase once greater than 33 to 56 percent NO_x reduction was reached. Corresponding NO_x levels ranged from 280 to 390 ppm (0.37 to 0.52 lb/MMBtu), while CO ranged from 8 to 60 ppm. For the natural gas wall-fired boilers, the available data show that baseline CO values were not exceeded across a wide range of NO_x reductions, from 7 to 83 percent. The 7-percent reduction in NO_x without CO increase was due to NO_x reduction efforts from an already controlled California utility boiler with an initial NO_x level of only 60 ppm (0.007 lb/MMBtu). Test results on oil-fired boilers indicated a marked increase in CO when greater than 26 to 57 percent NO_x reduction was reached via combustion modification. For some boilers, increases in CO from baseline were relatively minor, with CO emissions never exceeding 40 to 50 ppm. Emissions data for one application of urea injection did not show any noticeable effect on CO.

Combustion control retrofit experience to date has revealed that fuel/air imbalances can cause large increases in CO emissions even at small NO_x reduction levels. Modifications may be

Table 7-11. Summary of NO_x reduction levels achieved when low-NO_x CO = baseline (uncontrolled) CO

Fuel Type	Boiler Type	NO_x Reduction Achieved, CO = baseline CO (%)
Bituminous coal	Wall-fired	33 to 56
	Tangential	43 to 57
	Cyclone	61[a]
Natural gas	Wall-fired	7 to 83
	Tangential	17[a]
Heavy (residual) oil	Wall-fired	26 to 67
	Tangential	48[a]

[a]Data for one unit only.

necessary to adjust burner performance to balance air and fuel as part of the NO_x control retrofit. Therefore, CO versus NO_x response in these cases cannot be predicted using the results of this section and must await site-specific evaluation. This may be especially true for certain coal-fired units, since coal-fired systems generally suffer more air/fuel imbalance than oil or natural gas-fired units. However, the data suggest that on the average, 40 to 50 percent NO_x reduction is possible from existing baseline levels without markedly affecting baseline CO emissions. Often, when NO_x controls are applied, the excess oxygen level of the burner must be increased to maintain CO at acceptable levels, limiting the amount of NO_x reduction that is feasible and resulting in some thermal efficiency loss.

Retrofit NO_x controls had little effect on UBC in flyash levels when burning highly reactive coal, as shown by data for eight boilers. Of the other wall-fired boiler data examined, post-retrofit UBC values did not increase markedly from baseline levels until greater than 29 to 57 percent NO_x reduction was achieved. The coal particle fineness also affects the UBC level to a certain degree—increasing fineness can offset some loss in combustion efficiency.

Although the data base on THC is too sparse to draw any definitive conclusions, limited test data available indicate that THC emissions from utility boilers are very low, less than 2 ppm for the boilers discussed in this section. This emission level was reported regardless of fuel type and whether operating under baseline or low NO_x conditions. The available data suggest minimal impact of combustion controls on THC.

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EXPLANATION OF APPENDICES A AND B

Appendices A and B contain data extracted from the EPA NURF data base on utility boiler NO_x emissions in the NESCAUM region, supplemented with revised utility data on unit size, age, furnace design, firing type, heat rate, NO_x emission factor, capacity factor, total 1987 NO_x emissions, and 1987 fuel consumption. The revised data were obtained from the ESEERCO[1] study and the following utilities/organizations:

- Northeast States for Coordinated Air Use Management (NESCAUM)
- United Illuminating Company
- Consolidated Edison Company of New York, Inc. (Con Edison)
- New York State Electric & Gas Corporation (NYSEG)
- Niagara Mohawk Power Corporation (NMPC)
- Public Service Electric and Gas Company (PSE&G)

Appendices A and B contain the NESCAUM boiler inventory for coal-fired units and oil-/gas-fired units, respectively. Two spreadsheets are included in each appendix.

In the first spreadsheet, the information is sorted according to age, furnace design, and firing type. Weighted average NO_x emission factors (WANEFs) and weighted average capacity factors are calculated for each furnace design/firing type category within each specified age group (0 to 20 years, 21 to 30 years, 31 to 40 years, and greater than 40 years). The WANEFs, in units of "lb/MBtu," are calculated using the individual NO_x emission factors (NEF) and boiler sizes (MW) as follows:

$$WANEF = \frac{\sum NEF_i \, MW_i}{\sum MW_i}$$

The weighted average capacity factors (WACFs) are calculated with the individual factors (CF) and boiler sizes (MW) as follows:

$$WACF = \frac{\sum CF_i \, MW_i}{\sum MW_i}$$

[1]Hunter, S. C., "NO_x Emissions from Fossil Fuel Power Plants in New York State," KVB Report No. EP85-6, prepared for the Empire State Electric Energy Research Corporation, August 1989.

The data can be used to identify the units within a specific age and design group and the representative capacity and NO_x emission factors.

In the second spreadsheet, the information is sorted alphabetically according to the state, utility, and plant names. The organization of the data facilitates the location of specific boilers of interest.

At the end of each spreadsheet is a total for the 1987 NO_x emissions, in tons; the capacity, in MW; and the number of units used for that spreadsheet.

APPENDIX A

NESCAUM BOILER INVENTORY—COAL-FIRED UNITS

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
NY	NEW YORK STATE ELEC & GAS CORP	KINTIGH	1	675	7	Dry	Opposed	9,416	0.55	81	100	0	0	12,111
MA	HOLYOKE WATER POWER CO	MOUNT TOM	1	147	30	Dry	Wall	9,700	0.80	88	100	0	0	4,416
NJ	VINELAND CITY OF	HOWARD DOWN	* 1	25	21	Dry	Wall	10,000	0.57	90	95	5	0	564
NY	JAMESTOWN CITY OF	S A CARLSON	6	50	23	Dry	Wall	10,000	0.60	69	100	0	0	906
NY	ORANGE & ROCKLAND UTILS INC	LOVETT	5	200	22	Dry	Wall	10,593	0.56	32	61	6	33	1,679
		***** AVERAGES *****		106					0.65	60				
CT	UNITED ILLUMINATING CO	BRIDGEPORT HARBOR	3	385	23	Dry	Tangential	9,400	0.60	67	98	2	0	6,379
MA	NEW ENGLAND POWER CO	BRAYTON POINT	1	260	28	Dry	Tangential	9,600	0.70	66	99	1	0	5,053
MA	NEW ENGLAND POWER CO	BRAYTON POINT	2	260	27	Dry	Tangential	9,600	0.70	80	91	9	0	6,093
NY	CENTRAL HUDSON GAS & ELEC CORP	DANSKAMMER	4	235	24	Dry	Tangential	9,950	0.58	49	90	0	10	2,893
NY	NIAGARA MOHAWK POWER CORP	DUNKIRK	4	195	30	Dry	Tangential	10,174	0.70	64	102	0	0	3,877
		***** AVERAGES *****		267					0.65	66				
MA	NEW ENGLAND POWER CO	BRAYTON POINT	3	600	22	Dry	Opposed	10,000	0.84	67	99	1	0	14,838
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	HUDSON	2	660	23	Dry	Opposed	10,223	1.77	50	97	0	3	26,131
		***** AVERAGES *****		630					1.33	58				
NH	PUBLIC SERVICE CO OF NH	MERRIMACK	1	120	30	Wet	Cyclone	10,000	1.41	83	100	0	0	6,145
NH	PUBLIC SERVICE CO OF NH	MERRIMACK	2	338	23	Wet	Cyclone	10,000	1.40	58	100	0	0	12,100
NJ	ATLANTIC CITY ELECTRIC CO	B L ENGLAND	1	136	29	Wet	Cyclone	10,000	1.10	55	100	0	0	3,603
NJ	ATLANTIC CITY ELECTRIC CO	B L ENGLAND	2	163	27	Wet	Cyclone	10,000	1.10	73	100	0	0	5,696
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	MERCER	2	326	30	Wet	Wall	10,193	2.06	40	98	0	2	11,945
		***** AVERAGES *****		217					1.52	57				

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
MA	NEW ENGLAND POWER CO	SALEM HARBOR	1	85	39	Dry	Wall	10,700	1.00	56	98	2	0	2,242
MA	NEW ENGLAND POWER CO	SALEM HARBOR	2	85	39	Dry	Wall	10,800	1.00	88	99	1	0	3,531
MA	NEW ENGLAND POWER CO	SALEM HARBOR	3	160	33	Dry	Wall	9,900	1.00	64	99	1	0	4,466
NH	PUBLIC SERVICE CO OF NH	SCHILLER	4	50	39	Dry	Wall	12,000	0.79	43	72	28	0	884
NH	PUBLIC SERVICE CO OF NH	SCHILLER	5	50	36	Dry	Wall	12,000	0.79	47	78	22	0	977
NH	PUBLIC SERVICE CO OF NH	SCHILLER	6	50	34	Dry	Wall	12,000	0.79	59	55	45	0	1,233
NJ	ATLANTIC CITY ELECTRIC CO	DEEPWATER	8	80	37	Dry	Wall	10,000	0.80	54	91	9	0	1,509
NJ	ATLANTIC CITY ELECTRIC CO	DEEPWATER	9	26	34	Dry	Wall	10,000	0.42		97	0	3	1,001
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		***** AVERAGES *****		73					0.89	59				
NY	CENTRAL HUDSON GAS & ELEC CORP	DANSKAMMER	3	125	32	Dry	Tangential	9,674	0.59	31	51	43	7	978
NY	NEW YORK STATE ELEC & GAS CORP	GOUDEY	* 13	82	40	Dry	Tangential	10,083	0.80	81	100	0	0	2,416
NY	NEW YORK STATE ELEC & GAS CORP	GREENIDGE	* 6	100	38	Dry	Tangential	10,478	0.45	47	98	2	0	1,021
NY	NEW YORK STATE ELEC & GAS CORP	MILLIKEN	1	169	36	Dry	Tangential	9,468	0.64	79	100	0	0	3,167
NY	NEW YORK STATE ELEC & GAS CORP	MILLIKEN	2	169	33	Dry	Tangential	9,373	0.63	76	100	0	0	3,067
NY	NIAGARA MOHAWK POWER CORP	C R HUNTLEY	67	185	33	Dry	Tangential	8,619	0.70	85	100	0	0	4,162
NY	NIAGARA MOHAWK POWER CORP	C R HUNTLEY	68	190	32	Dry	Tangential	9,752	0.70	69	100	0	0	3,903
NY	NIAGARA MOHAWK POWER CORP	DUNKIRK	1	90	40	Dry	Tangential	10,293	0.70	76	100	0	0	2,146
NY	NIAGARA MOHAWK POWER CORP	DUNKIRK	2	90	40	Dry	Tangential	10,601	0.70	84	100	0	0	2,459
NY	NIAGARA MOHAWK POWER CORP	DUNKIRK	3	195	31	Dry	Tangential	10,433	0.70	55	100	0	0	3,420
NY	ROCHESTER GAS & ELECTRIC CORP	RUSSELL	2	65	40	Dry	Tangential	10,270	0.52	56	100	0	0	858
NY	ROCHESTER GAS & ELECTRIC CORP	RUSSELL	3	65	38	Dry	Tangential	10,270	0.52	48	100	0	0	730
NY	ROCHESTER GAS & ELECTRIC CORP	RUSSELL	4	85	34	Dry	Tangential	9,300	0.45	58	100	0	0	906
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		***** AVERAGES *****		124					0.64	67				
NY	NEW YORK STATE ELEC & GAS CORP	HICKLING	* 3	50	39	Dry	Stoker	13,598	0.08	57	100	0	0	318
NY	NEW YORK STATE ELEC & GAS CORP	HICKLING	* 4	w/#3	39	Dry	Stoker	13,598			100	0	0	

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
MA	MONTAUP ELECTRIC CO	SOMERSET	5	74	40	Wet	Tangential	10,000	1.64	95	96	4	0	5,039
MA	MONTAUP ELECTRIC CO	SOMERSET	6	100	32	Wet	Tangential	10,000	0.60	95	96	4	0	2,507
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	MERCER	1	326	31	Wet	Wall	9,820	2.01	49	93	0	7	13,750
NY	NIAGARA MOHAWK POWER CORP	C R HUNTLEY	65	85	37	Wet	Vertical	10,934	1.10	70	100	0	0	3,135
NY	NIAGARA MOHAWK POWER CORP	C R HUNTLEY	66	85	36	Wet	Vertical	10,543	1.10	77	100	0	0	3,318
NY	ROCHESTER GAS & ELECTRIC CORP	BEEBEE	12	75	32	Wet	Wall	9,300	0.44	65	100	0	0	862
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		***** AVERAGES *****		124					1.42	67				
NY	NEW YORK STATE ELEC & GAS CORP	GREENIDGE	* 4,5	55	41	Dry	Wall	12,371	0.79	63	99	1	0	1,617
NJ	ATLANTIC CITY ELECTRIC CO	DEEPWATER	* 7	26	49	Dry	Vertical	10,000	0.42		85	15	0	656
NY	ROCHESTER GAS & ELECTRIC CORP	RUSSELL	1	53	43	Dry	Tangential	10,270	0.52	48	100	0	0	589
NY	NEW YORK STATE ELEC & GAS CORP	HICKLING	* 1	37	43	Dry	Stoker	14,648	0.08	58	100	0	0	263
NY	NEW YORK STATE ELEC & GAS CORP	HICKLING	* 2	w/#1	43	Dry	Stoker	14,648			100	0	0	
NY	NEW YORK STATE ELEC & GAS CORP	JENNISON	* 1	33	46	Dry	Stoker	15,803	0.35	50	100	0	0	403
NY	NEW YORK STATE ELEC & GAS CORP	JENNISON	* 2	w/#1	46	Dry	Stoker	15,803			100	0	0	
NY	NEW YORK STATE ELEC & GAS CORP	JENNISON	* 3	38	41	Dry	Stoker	15,263	0.35	46	100	0	0	412
NY	NEW YORK STATE ELEC & GAS CORP	JENNISON	* 4	w/#3	41	Dry	Stoker	15,263			100	0	0	
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		***** AVERAGES *****		36					0.26	51				
NY	NIAGARA MOHAWK POWER CORP	C R HUNTLEY	63	85	48	Wet	Vertical	11,823	1.10	35	100	0	0	1,705
NY	NIAGARA MOHAWK POWER CORP	C R HUNTLEY	64	85	42	Wet	Vertical	11,656	1.10	18	100	0	0	868
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		***** AVERAGES *****		85					1.10	27				

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
NY	NEW YORK STATE ELEC & GAS CORP	GOUDEY	* 11	44		Dry	Opposed	12,550	0.83	54	98	2	0	1,020
NY	NEW YORK STATE ELEC & GAS CORP	GOUDEY	* 12	w/#11		Dry	Opposed	12,550			98	2	0	

TOTAL NOx EMISSIONS (Tons) FOR COAL UNITS = 205,973
TOTAL CAPACITY (MW) OF COAL UNITS = 8,222
TOTAL NUMBER OF COAL UNITS = 59

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
CT	UNITED ILLUMINATING CO	BRIDGEPORT HARBOR	3	385	23	Dry	Tangential	9,400	0.60	67	98	2	0	6,379
MA	HOLYOKE WATER POWER CO	MOUNT TOM	1	147	30	Dry	Wall	9,700	0.80	88	100	0	0	4,416
MA	MONTAUP ELECTRIC CO	SOMERSET	5	74	40	Wet	Tangential	10,000	1.64	95	96	4	0	5,039
MA	MONTAUP ELECTRIC CO	SOMERSET	6	100	32	Wet	Tangential	10,000	0.60	95	96	4	0	2,507
MA	NEW ENGLAND POWER CO	BRAYTON POINT	1	260	28	Dry	Tangential	9,600	0.70	66	99	1	0	5,053
MA	NEW ENGLAND POWER CO	BRAYTON POINT	2	260	27	Dry	Tangential	9,600	0.70	80	91	9	0	6,093
MA	NEW ENGLAND POWER CO	BRAYTON POINT	3	600	22	Dry	Opposed	10,000	0.84	67	99	1	0	14,838
MA	NEW ENGLAND POWER CO	SALEM HARBOR	1	85	39	Dry	Wall	10,700	1.00	56	98	2	0	2,242
MA	NEW ENGLAND POWER CO	SALEM HARBOR	2	85	39	Dry	Wall	10,800	1.00	88	99	1	0	3,531
MA	NEW ENGLAND POWER CO	SALEM HARBOR	3	160	33	Dry	Wall	9,900	1.00	64	99	1	0	4,466
NH	PUBLIC SERVICE CO OF NH	MERRIMACK	1	120	30	Wet	Cyclone	10,000	1.41	83	100	0	0	6,145
NH	PUBLIC SERVICE CO OF NH	MERRIMACK	2	338	23	Wet	Cyclone	10,000	1.40	58	100	0	0	12,100
NH	PUBLIC SERVICE CO OF NH	SCHILLER	4	50	39	Dry	Wall	12,000	0.79	43	72	28	0	884
NH	PUBLIC SERVICE CO OF NH	SCHILLER	5	50	36	Dry	Wall	12,000	0.79	47	78	22	0	977
NH	PUBLIC SERVICE CO OF NH	SCHILLER	6	50	34	Dry	Wall	12,000	0.79	59	55	45	0	1,233
NJ	ATLANTIC CITY ELECTRIC CO	B L ENGLAND	1	136	29	Wet	Cyclone	10,000	1.10	55	100	0	0	3,603
NJ	ATLANTIC CITY ELECTRIC CO	B L ENGLAND	2	163	27	Wet	Cyclone	10,000	1.10	73	100	0	0	5,696
NJ	ATLANTIC CITY ELECTRIC CO	DEEPWATER	8	80	37	Dry	Wall	10,000	0.80	54	91	9	0	1,509
NJ	ATLANTIC CITY ELECTRIC CO	DEEPWATER	9	26	34	Dry	Wall	10,000	0.42		97	0	3	1,001
NJ	ATLANTIC CITY ELECTRIC CO	DEEPWATER	* 7	26	49	Dry	Vertical	10,000	0.42		85	15	0	656
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	HUDSON	2	660	23	Dry	Opposed	10,223	1.77	50	97	0	3	26,131
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	MERCER	1	326	31	Wet	Wall	9,820	2.01	49	93	0	7	13,750
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	MERCER	2	326	30	Wet	Wall	10,193	2.06	40	98	0	2	11,945
NJ	VINELAND CITY OF	HOWARD DOWN	* 1	25	21	Dry	Wall	10,000	0.57	90	95	5	0	564
NY	CENTRAL HUDSON GAS & ELEC CORP	DANSKAMMER	3	125	32	Dry	Tangential	9,674	0.59	31	51	43	7	978
NY	CENTRAL HUDSON GAS & ELEC CORP	DANSKAMMER	4	235	24	Dry	Tangential	9,950	0.58	49	90	0	10	2,893
NY	JAMESTOWN CITY OF	S A CARLSON	6	50	23	Dry	Wall	10,000	0.60	69	100	0	0	906
NY	NEW YORK STATE ELEC & GAS CORP	GOUDEY	* 11	44		Dry	Opposed	12,550	0.83	54	98	2	0	1,020
NY	NEW YORK STATE ELEC & GAS CORP	GOUDEY	* 12	w/#11		Dry	Opposed	12,550			98	2	0	
NY	NEW YORK STATE ELEC & GAS CORP	GOUDEY	* 13	82	40	Dry	Tangential	10,083	0.80	81	100	0	0	2,416

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
NY	NEW YORK STATE ELEC & GAS CORP	GREENIDGE	* 4,5	55	41	Dry	Wall	12,371	0.79	63	99	1	0	1,617
NY	NEW YORK STATE ELEC & GAS CORP	GREENIDGE	* 6	100	38	Dry	Tangential	10,478	0.45	47	98	2	0	1,021
NY	NEW YORK STATE ELEC & GAS CORP	HICKLING	* 1	37	43	Dry	Stoker	14,648	0.08	58	100	0	0	263
NY	NEW YORK STATE ELEC & GAS CORP	HICKLING	* 2	w/#1	43	Dry	Stoker	14,648			100	0	0	
NY	NEW YORK STATE ELEC & GAS CORP	HICKLING	* 3	50	39	Dry	Stoker	13,598	0.08	57	100	0	0	318
NY	NEW YORK STATE ELEC & GAS CORP	HICKLING	* 4	w/#3	39	Dry	Stoker	13,598			100	0	0	
NY	NEW YORK STATE ELEC & GAS CORP	JENNISON	* 1	33	46	Dry	Stoker	15,803	0.35	50	100	0	0	403
NY	NEW YORK STATE ELEC & GAS CORP	JENNISON	* 2	w/#1	46	Dry	Stoker	15,803			100	0	0	
NY	NEW YORK STATE ELEC & GAS CORP	JENNISON	* 3	38	41	Dry	Stoker	15,263	0.35	46	100	0	0	412
NY	NEW YORK STATE ELEC & GAS CORP	JENNISON	* 4	w/#3	41	Dry	Stoker	15,263			100	0	0	
NY	NEW YORK STATE ELEC & GAS CORP	KINTIGH	1	675	7	Dry	Opposed	9,416	0.55	81	100	0	0	12,111
NY	NEW YORK STATE ELEC & GAS CORP	MILLIKEN	1	169	36	Dry	Tangential	9,468	0.64	79	100	0	0	3,167
NY	NEW YORK STATE ELEC & GAS CORP	MILLIKEN	2	169	33	Dry	Tangential	9,373	0.63	76	100	0	0	3,067
NY	NIAGARA MOHAWK POWER CORP	C R HUNTLEY	63	85	48	Wet	Vertical	11,823	1.10	35	100	0	0	1,705
NY	NIAGARA MOHAWK POWER CORP	C R HUNTLEY	64	85	42	Wet	Vertical	11,656	1.10	18	100	0	0	868
NY	NIAGARA MOHAWK POWER CORP	C R HUNTLEY	65	85	37	Wet	Vertical	10,934	1.10	70	100	0	0	3,135
NY	NIAGARA MOHAWK POWER CORP	C R HUNTLEY	66	85	36	Wet	Vertical	10,543	1.10	77	100	0	0	3,318
NY	NIAGARA MOHAWK POWER CORP	C R HUNTLEY	67	185	33	Dry	Tangential	8,619	0.70	85	100	0	0	4,162
NY	NIAGARA MOHAWK POWER CORP	C R HUNTLEY	68	190	32	Dry	Tangential	9,752	0.70	69	100	0	0	3,903
NY	NIAGARA MOHAWK POWER CORP	DUNKIRK	1	90	40	Dry	Tangential	10,293	0.70	76	100	0	0	2,146
NY	NIAGARA MOHAWK POWER CORP	DUNKIRK	2	90	40	Dry	Tangential	10,601	0.70	84	100	0	0	2,459
NY	NIAGARA MOHAWK POWER CORP	DUNKIRK	3	195	31	Dry	Tangential	10,433	0.70	55	100	0	0	3,420
NY	NIAGARA MOHAWK POWER CORP	DUNKIRK	4	195	30	Dry	Tangential	10,174	0.70	64	102	0	0	3,877
NY	ORANGE & ROCKLAND UTILS INC	LOVETT	5	200	22	Dry	Wall	10,593	0.56	32	61	6	33	1,679
NY	ROCHESTER GAS & ELECTRIC CORP	BEEBEE	12	75	32	Wet	Wall	9,300	0.44	65	100	0	0	862
NY	ROCHESTER GAS & ELECTRIC CORP	RUSSELL	1	53	43	Dry	Tangential	10,270	0.52	48	100	0	0	589
NY	ROCHESTER GAS & ELECTRIC CORP	RUSSELL	2	65	40	Dry	Tangential	10,270	0.52	56	100	0	0	858
NY	ROCHESTER GAS & ELECTRIC CORP	RUSSELL	3	65	38	Dry	Tangential	10,270	0.52	48	100	0	0	730
NY	ROCHESTER GAS & ELECTRIC CORP	RUSSELL	4	85	34	Dry	Tangential	9,300	0.45	58	100	0	0	906

TOTAL NOx EMISSIONS (Tons) FOR COAL UNITS = 205,973
TOTAL CAPACITY (MW) OF COAL UNITS = 8,222
TOTAL NUMBER OF COAL UNITS = 59

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

APPENDIX B

NESCAUM BOILER INVENTORY—OIL-/GAS-FIRED UNITS

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
MA	NEW ENGLAND POWER CO	BRAYTON POINT	4	450	17	Dry	Wall	10,700	0.30	46	0	100	0	2,930
MA	NEW ENGLAND POWER CO	SALEM HARBOR	4	450	19	Dry	Wall	10,600	0.50	59	0	100	0	6,145
MA	TAUNTON CITY OF	CLEARY FLOOD	*8 CA9	28	16	Dry	Wall	10,000	0.34	11	0	100	0	44
ME	CENTRAL MAINE POWER CO	WILLIAM F. WYMAN	4	632	13	Dry	Wall	10,000	0.21	34	0	100	0	1,990
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	LINDEN	4	93	19	Dry	Wall	11,240	0.44	15	0	100	0	696
NY	NIAGARA MOHAWK POWER CORP	OSWEGO	5	850	14	Dry	Wall	10,503	1.00	21	0	99	1	8,368
NY	NIAGARA MOHAWK POWER CORP	OSWEGO	6	850	10	Dry	Wall	11,339	0.27	18	0	99	1	2,033
NY	POWER AUTHORITY OF STATE OF NY	CHARLES POLETTI	6	825	15	No data	Wall	10,000	0.25	43	0	38	62	3,845
VT	BURLINGTON CITY OF	J C MCNEIL	1	50	7	Wet	Wall	10,000	0.28	3	0	100	0	20
		***** AVERAGES *****		470					0.44	33				
CT	CONNECTICUT LIGHT & POWER CO	MONTVILLE	6	415	20	Dry	Tangential	11,700	0.30	22	0	100	0	1,413
CT	UNITED ILLUMINATING CO	NEW HAVEN HARBOR	* 1	447	16	Dry	Tangential	9,400	0.30	72	0	88	12	3,984
MA	BOSTON EDISON CO	MYSTIC	7	585	16	Dry	Tangential	10,000	0.20	59	0	50	50	3,011
NH	PUBLIC SERVICE CO OF NH	NEWINGTON	1	400	17	Dry	Tangential	10,900	0.46	54	0	100	0	4,719
NJ	ATLANTIC CITY ELECTRIC CO	B L ENGLAND	3	176	17	Dry	Tangential	10,000	0.40	50	0	100	0	1,542
NY	CENTRAL HUDSON GAS & ELEC CORP	ROSETON	1	600	17	Dry	Tangential	9,185	0.48	58	0	100	0	6,672
NY	CENTRAL HUDSON GAS & ELEC CORP	ROSETON	2	540	17	Dry	Tangential	9,185	0.44	60	0	100	0	5,749
NY	LONG ISLAND LIGHTING CO	NORTHPORT	3	370	19	Dry	Tangential	9,360	0.30	74	0	100	0	3,362
NY	LONG ISLAND LIGHTING CO	NORTHPORT	4	370	14	Dry	Tangential	9,360	0.30	64	0	100	0	2,890
NY	ORANGE & ROCKLAND UTILS INC	BOWLINE POINT	1	580	19	Dry	Tangential	9,881	0.22	40	0	77	23	2,239
		***** AVERAGES *****		448					0.34	55				
CT	CONNECTICUT LIGHT & POWER CO	MIDDLETOWN	4	415	18	Wet	Opposed	13,000	0.30	19	0	100	0	1,358
MA	CANAL ELECTRIC CO	CANAL	2	581	15	Dry	Opposed	9,743	0.30	52	0	100	0	5,187
NY	ORANGE & ROCKLAND UTILS INC	BOWLINE POINT	2	570	17	Dry	Opposed	9,240	0.21	51	0	38	62	2,483
		***** AVERAGES *****		522					0.27	43				

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
MA	CAMBRIDGE ELECTRIC LIGHT CO	BLACKSTONE STREET	*11	144	28	Dry	Wall	10,000	0.32	3	0	44	56	51
MA	CAMBRIDGE ELECTRIC LIGHT CO	BLACKSTONE STREET	*12	617	28	Dry	Wall	10,000	0.29	1	0	40	60	53
NY	ORANGE & ROCKLAND UTILS INC	LOVETT	4	198	25	Dry	Wall	9,963	1.40	27	5	20	75	3,238
		***** AVERAGES *****		320					0.52	6				
CT	CONNECTICUT LIGHT & POWER CO	NORWALK HARBOR	2	172	28	Dry	Tangential	9,900	0.30	69	0	100	0	1,548
MA	BOSTON EDISON CO	MYSTIC	6	149	30	Dry	Tangential	10,000	0.30	45	0	100	0	888
ME	CENTRAL MAINE POWER CO	WILLIAM F. WYMAN	3	114	26	Dry	Tangential	10,000	0.34	54	0	100	0	918
NY	CONSOLIDATED EDISON CO OF NY	74TH STREET	* 121	57	29	No data	Tangential	9,650	0.30	41	0	100	0	291
NY	CONSOLIDATED EDISON CO OF NY	ARTHUR KILL	30	501	22	Dry	Tangential	9,300	0.25	28	0	100	0	1,451
NY	CONSOLIDATED EDISON CO OF NY	ASTORIA	40	375	30	Dry	Tangential	9,530	0.17	20	0	58	42	533
NY	CONSOLIDATED EDISON CO OF NY	ASTORIA	50	375	29	Dry	Tangential	9,560	0.17	41	0	44	56	1,117
NY	CONSOLIDATED EDISON CO OF NY	RAVENSWOOD	10	390	29	Dry	Tangential	9,550	0.22	44	0	24	76	1,585
NY	CONSOLIDATED EDISON CO OF NY	RAVENSWOOD	20	390	28	Dry	Tangential	9,550	0.25	38	0	26	74	1,570
NY	CONSOLIDATED EDISON CO OF NY	RAVENSWOOD	30	972	26	Dry	Tangential	9,590	0.25	35	0	50	50	3,555
NY	LONG ISLAND LIGHTING CO	E F BARRETT	2	185	28	Dry	Tangential	9,385	0.32	75	0	23	77	1,803
NY	LONG ISLAND LIGHTING CO	NORTHPORT	1	370	24	Dry	Tangential	9,360	0.30	65	0	100	0	2,960
NY	LONG ISLAND LIGHTING CO	NORTHPORT	2	370	23	Dry	Tangential	9,360	0.30	65	0	100	0	2,962
		***** AVERAGES *****		340					0.25	44				
CT	CONNECTICUT LIGHT & POWER CO	MIDDLETOWN	3	239	27	Wet	Opposed	9,900	0.90	27	0	100	0	2,563
MA	BOSTON EDISON CO	NEW BOSTON	1	388	26	Dry	Opposed	10,000	0.50	52	0	81	19	4,413
MA	BOSTON EDISON CO	NEW BOSTON	2	388	24	Dry	Opposed	10,000	0.50	64	0	75	25	5,477
MA	CANAL ELECTRIC CO	CANAL	1	569	23	Dry	Opposed	9,006	0.75	60	0	100	0	7,679
ME	BANGOR HYDRO-ELECTRIC CO	GRAHAM STATION	5	27	27	Dry	Opposed	10,000	0.45	12	0	100	0	64
		***** AVERAGES *****		322					0.65	54				
CT	UNITED ILLUMINATING CO	BRIDGEPORT HARBOR	2	170	30	Dry	Cyclone	10,100	0.50	58	0	100	0	2,181

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	HUDSON	1	455	26	Wet	Cyclone	11,713	0.68	21	0	10	90	3,395
		***** AVERAGES *****		313					0.63	31				
CT	CONNECTICUT LIGHT & POWER CO	DEVON	3	66	40	Dry	Wall	11,400	0.30	12	0	100	0	116
MA	CAMBRIDGE ELECTRIC LIGHT CO	KENDALL SQUARE	3	30	37	Dry	Wall	10,000	0.28	68	0	24	76	249
ME	CENTRAL MAINE POWER CO	WILLIAM F. WYMAN	1	50	34	Dry	Wall	10,000	0.34	20	0	100	0	146
ME	CENTRAL MAINE POWER CO	WILLIAM F. WYMAN	2	50	33	Dry	Wall	10,000	0.34	25	0	100	0	185
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	BERGEN	1	325	32	Wet	Wall	10,580	1.08	44	0	6	94	7,216
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	BERGEN	2	325	31	Wet	Wall	10,776	1.08	34	0	5	95	5,728
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	BURLINGTON	7	205	36	Wet	Wall	12,228	0.47	10	0	100	0	518
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	LINDEN	2	260	34	Wet	Wall	12,019	0.44	12	0	100	0	707
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	LINDEN	* 11	87	34	Wet	Wall	11,240	0.44	22	0	100	0	1,009
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	LINDEN	* 12	87	34	Wet	Wall	11,240	0.44	12	0	100	0	563
NY	CONSOLIDATED EDISON CO OF NY	59TH STREET	* 110	72	39	Dry	Wall	9,650	0.38	1	0	100	0	11
NY	CONSOLIDATED EDISON CO OF NY	ARTHUR KILL	20	350	32	Dry	Wall	9,650	0.33	20	0	100	0	967
NY	CONSOLIDATED EDISON CO OF NY	EAST RIVER	70	175	36	Dry	Wall	9,950	0.35	21	0	38	62	560
NY	CONSOLIDATED EDISON CO OF NY	HUDSON AVENUE	100	178	40	Dry	Wall	12,421	0.47	46	0	100	0	2,094
NY	ORANGE & ROCKLAND UTILS INC	LOVETT	* 1	17	36	Dry	Wall	10,000	0.52	2	0	0	100	8
NY	ORANGE & ROCKLAND UTILS INC	LOVETT	* 2	20	36	Dry	Wall	10,000	0.52	4	0	6	94	19
NY	ORANGE & ROCKLAND UTILS INC	LOVETT	* 3	69	36	Dry	Wall	9,300	0.38	31	0	8	92	333
RI	NEW ENGLAND POWER CO	SOUTH STREET	* 122	98	36	Dry	Wall	10,000	0.45	27	0	47	53	528
		***** AVERAGES *****		137					0.58	25				
CT	UNITED ILLUMINATING CO	ENGLISH	8	37	40	Dry	Vertical	12,200	0.30	8	0	100	0	47
NY	NIAGARA MOHAWK POWER CORP	OSWEGO	4	90	39	Wet	Vertical	11,916	0.70	18	0	100	0	604
		***** AVERAGES *****		64					0.58	15				
CT	CONNECTICUT LIGHT & POWER CO	DEVON	8	104	33	Dry	Tangential	10,600	0.30	50	0	100	0	727

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
CT	CONNECTICUT LIGHT & POWER CO	MONTVILLE	5	85	37	Dry	Tangential	11,900	0.30	57	0	15	85	761
CT	CONNECTICUT LIGHT & POWER CO	NORWALK HARBOR	1	163	31	Dry	Tangential	10,500	0.30	57	0	100	0	1,285
MA	BOSTON EDISON CO	MYSTIC	4	135	34	Dry	Tangential	10,000	0.30	57	0	100	0	1,018
MA	BOSTON EDISON CO	MYSTIC	5	135	32	Dry	Tangential	10,000	0.30	59	0	100	0	1,050
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	KEARNY	7	157	38	Wet	Tangential	15,234	0.23	4	0	100	0	85
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	KEARNY	8	157	38	Wet	Tangential	13,511	0.23	7	0	95	0	160
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	SEWAREN	4	127	40	Wet	Tangential	12,280	0.19	24	0	11	89	411
NY	CENTRAL HUDSON GAS & ELEC CORP	DANSKAMMER	1	60	40	Dry	Tangential	9,464	0.24	64	0	27	73	384
NY	CENTRAL HUDSON GAS & ELEC CORP	DANSKAMMER	2	60	37	Dry	Tangential	9,464	0.24	73	0	26	74	434
NY	CONSOLIDATED EDISON CO OF NY	74TH STREET	* 120	58	35	No data	Tangential	9,650	0.30	40	0	100	0	288
NY	CONSOLIDATED EDISON CO OF NY	74TH STREET	* 122	58	32	No data	Tangential	9,650	0.30	40	0	100	0	288
NY	LONG ISLAND LIGHTING CO	E F BARRETT	1	185	35	Dry	Tangential	9,385	0.29	77	0	24	76	1,702
NY	LONG ISLAND LIGHTING CO	FAR ROCKAWAY	4	114	38	Dry	Tangential	10,000	0.00	53	0	36	64	0
NY	LONG ISLAND LIGHTING CO	GLENWOOD	4	118	39	Dry	Tangential	10,200	0.23	34	0	24	76	412
NY	LONG ISLAND LIGHTING CO	GLENWOOD	5	118	37	Dry	Tangential	10,200	0.23	53	0	30	70	653
NY	LONG ISLAND LIGHTING CO	PORT JEFFERSON	3	185	33	Dry	Tangential	9,385	0.36	63	0	100	0	1,737
NY	LONG ISLAND LIGHTING CO	PORT JEFFERSON	4	185	31	Dry	Tangential	9,385	0.36	66	0	100	0	1,800
NY	NIAGARA MOHAWK POWER CORP	ALBANY	1	97	38	Dry	Tangential	10,801	0.14	74	0	12	88	470
NY	NIAGARA MOHAWK POWER CORP	ALBANY	2	97	38	Dry	Tangential	10,656	0.14	42	0	12	88	267
NY	NIAGARA MOHAWK POWER CORP	ALBANY	3	97	37	Dry	Tangential	10,777	0.14	71	0	13	87	459
NY	NIAGARA MOHAWK POWER CORP	ALBANY	4	97	36	Dry	Tangential	10,905	0.14	55	0	14	86	363
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		***** AVERAGES *****		118					0.25	50				
CT	CONNECTICUT LIGHT & POWER CO	MIDDLETOWN	1	69	37	Wet	Opposed	12,500	0.30	23	0	100	0	257
CT	CONNECTICUT LIGHT & POWER CO	MIDDLETOWN	2	114	33	Wet	Opposed	11,400	0.30	40	0	100	0	681
MA	WESTERN MASSACHUSETTS ELEC CO	WEST SPRINGFIELD	2	50	39	Dry	Opposed	12,800	0.25	13	0	100	0	89
MA	WESTERN MASSACHUSETTS ELEC CO	WEST SPRINGFIELD	3	114	34	Dry	Opposed	11,000	0.25	60	0	44	56	819
NY	CONSOLIDATED EDISON CO OF NY	ASTORIA	10	175	38	Dry	Opposed	9,950	0.28	31	0	33	67	672
NY	CONSOLIDATED EDISON CO OF NY	ASTORIA	20	173	37	Dry	Opposed	9,950	0.27	57	0	28	72	1,155
NY	CONSOLIDATED EDISON CO OF NY	ASTORIA	30	361	33	Dry	Opposed	9,650	0.31	51	0	32	68	2,436
NY	CONSOLIDATED EDISON CO OF NY	EAST RIVER	50	164	40	Dry	Opposed	10,230	0.23	46	0	98	2	767
NY	CONSOLIDATED EDISON CO OF NY	EAST RIVER	60	156	40	Dry	Opposed	9,987	0.29	60	0	57	43	1,193
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* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
		***** AVERAGES *****		153					0.28	47				
CT	UNITED ILLUMINATING CO	BRIDGEPORT HARBOR	1	82	34	Dry	Cyclone	10,200	0.50	55	0	100	0	1,013
NJ	ATLANTIC CITY ELECTRIC CO	DEEPWATER	* 1	82	33	Wet	Cyclone	10,000	0.44	39	0	22	78	618
NJ	JERSEY CENTRAL POWER&LIGHT CO	SAYREVILLE	* 7	110	37	N/R	Cyclone	10,000	0.49	19				256
NJ	JERSEY CENTRAL POWER&LIGHT CO	SAYREVILLE	* 8	115	33	N/R	Cyclone	10,000	0.49	30				375
NJ	JERSEY CENTRAL POWER&LIGHT CO	WERNER	4	60	38	N/R	Cyclone	10,000	0.46	21	0	100	0	255
		***** AVERAGES *****		90					0.48	33				
MA	CAMBRIDGE ELECTRIC LIGHT CO	BLACKSTONE STREET	* 5	380	42	Dry	Wall	10,000	0.24	0	0	12	88	18
MA	CAMBRIDGE ELECTRIC LIGHT CO	BLACKSTONE STREET	* 6	380	42	Dry	Wall	10,000	0.33	1	0	48	52	43
MA	CAMBRIDGE ELECTRIC LIGHT CO	KENDALL SQUARE	* 1	20	42	Dry	Wall	10,000	0.48	63	0	16	84	267
MA	CAMBRIDGE ELECTRIC LIGHT CO	KENDALL SQUARE	* 2	20	42	Dry	Wall	10,000	0.48	72	0	21	79	304
MA	COMMONWEALTH ELECTRIC CO	CANNON STREET	1	25	44	Dry	Wall	10,000	0.41	22	0	26	74	98
MA	COMMONWEALTH ELECTRIC CO	CANNON STREET	2	25	44	Dry	Wall	10,000	0.41	22	0	26	74	98
MA	COMMONWEALTH ELECTRIC CO	CANNON STREET	* 3	34	41	Dry	Wall	10,000	0.27	44	0	28	72	175
NH	PUBLIC SERVICE CO OF NH	SCHILLER	3	25	42	Dry	Wall	17,500	0.43	16				130
NJ	JERSEY CENTRAL POWER&LIGHT CO	GILBERT	* 1, 2	45	61	N/R	Wall	10,000	0.01	9	0	28	72	2
NJ	JERSEY CENTRAL POWER&LIGHT CO	SAYREVILLE	* 2, 3	45	52	Dry	Wall	10,000	0.23	0	0	100	0	2
NY	CONSOLIDATED EDISON CO OF NY	59TH STREET	* 111	50	41	Dry	Wall	9,650	0.41	29	0	100	0	251
RI	NEW ENGLAND POWER CO	MANCHESTER STREET	* 9	40	50	Dry	Wall	13,800	0.40	33	0	36	64	320
RI	NEW ENGLAND POWER CO	MANCHESTER STREET	*10	46	44	Dry	Wall	13,800	0.40	37	0	50	50	410
RI	NEW ENGLAND POWER CO	MANCHESTER STREET	*11	46	42	Dry	Wall	13,700	0.40	22	0	60	40	245
RI	NEW ENGLAND POWER CO	SOUTH STREET	* 121	48	73	Dry	Wall	10,000	0.45	68	0	47	53	645
		***** AVERAGES *****		82					0.31	12				
CT	UNITED ILLUMINATING CO	ENGLISH	7	35	43	Dry	Vertical	13,200	0.30	5	0	100	0	32
NJ	JERSEY CENTRAL POWER&LIGHT CO	SAYREVILLE	* 4	29	42	Dry	Vertical	10,000	0.22	10	0	4	96	27
NJ	JERSEY CENTRAL POWER&LIGHT CO	SAYREVILLE	* 5, 6	45	46	N/R	Vertical	10,000	0.53	6	0	1	99	66

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
NY	NIAGARA MOHAWK POWER CORP	OSWEGO	3	75	42	Dry	Vertical	12,616	0.53	6	0	0	100	141
		***** AVERAGES *****		46					0.44	7				
MA	WESTERN MASSACHUSETTS ELEC CO	WEST SPRINGFIELD	1	46	42	Dry	Tangential	13,800	0.25	14	0	100	0	96
NJ	JERSEY CENTRAL POWER&LIGHT CO	GILBERT	3	73	41	N/R	Tangential	10,000	0.40	21				94
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	SEWAREN	1	111	43	Wet	Tangential	15,279	0.19	5	0	12	88	77
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	SEWAREN	2	108	43	Wet	Tangential	13,134	0.19	20	0	6	94	235
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	SEWAREN	3	116	42	Wet	Tangential	14,091	0.19	12	0	10	90	163
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 41	48	43	No data	Tangential	9,650	0.18	29	0	47	53	107
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 42	48	42	No data	Tangential	9,650	0.18	29	0	47	53	107
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 51	65	54	No data	Tangential	9,650	0.18	28	0	35	65	137
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 52	70	53	No data	Tangential	9,650	0.18	27	0	38	62	142
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 61	89	50	No data	Tangential	10,220	0.18	25	0	34	66	176
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 62	87	50	No data	Tangential	9,650	0.17	18	0	10	90	112
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 80	126	42	No data	Tangential	10,230	0.16	52	0	26	74	455
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 90	128	42	No data	Tangential	10,070	0.14	67	0	23	77	529
NY	LONG ISLAND LIGHTING CO	PORT JEFFERSON	1	45	43	Dry	Tangential	9,385	0.36	27	0	100	0	179
NY	LONG ISLAND LIGHTING CO	PORT JEFFERSON	2	45	41	Dry	Tangential	9,385	0.36	29	0	100	0	193
		***** AVERAGES *****		80					0.20	28				
NY	CONSOLIDATED EDISON CO OF NY	59TH STREET	* 112	38		Dry	Wall	10,779	0.44	34	0	100	0	268
NY	CONSOLIDATED EDISON CO OF NY	59TH STREET	* 114	73		Dry	Tangential	9,650	0.22	36	0	100	0	244
NY	CONSOLIDATED EDISON CO OF NY	59TH STREET	* 115	73		Dry	Tangential	9,650	0.22	33	0	100	0	224
		***** AVERAGES *****		73					0.22	34				
CT	CONNECTICUT LIGHT & POWER CO	DEVON	4	48		Dry	Wall	12,700	0.30	13				103

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	LINDEN	* 13	87		Wet	Wall	11,240	0.44	27	0	100	0	1,208
NY	CONSOLIDATED EDISON CO OF NY	59TH STREET	* 113	47		Dry	Wall	9,650	0.41	28	0	100	0	225
		***** AVERAGES *****		61					0.39	24				

TOTAL NOx EMISSIONS (Tons) FOR OIL/GAS UNITS = 176,266

TOTAL CAPACITY (MW) OF OIL/GAS UNITS = 27,883

TOTAL NUMBER OF OIL/GAS UNITS = 141

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
CT	CONNECTICUT LIGHT & POWER CO	DEVON	3	66	40	Dry	Wall	11,400	0.30	12	0	100	0	116
CT	CONNECTICUT LIGHT & POWER CO	DEVON	4	48		Dry	Wall	12,700	0.30	13				103
CT	CONNECTICUT LIGHT & POWER CO	DEVON	8	104	33	Dry	Tangential	10,600	0.30	50	0	100	0	727
CT	CONNECTICUT LIGHT & POWER CO	MIDDLETOWN	1	69	37	Wet	Opposed	12,500	0.30	23	0	100	0	257
CT	CONNECTICUT LIGHT & POWER CO	MIDDLETOWN	2	114	33	Wet	Opposed	11,400	0.30	40	0	100	0	681
CT	CONNECTICUT LIGHT & POWER CO	MIDDLETOWN	3	239	27	Wet	Opposed	9,900	0.90	27	0	100	0	2,563
CT	CONNECTICUT LIGHT & POWER CO	MIDDLETOWN	4	415	18	Wet	Opposed	13,000	0.30	19	0	100	0	1,358
CT	CONNECTICUT LIGHT & POWER CO	MONTVILLE	5	85	37	Dry	Tangential	11,900	0.30	57	0	15	85	761
CT	CONNECTICUT LIGHT & POWER CO	MONTVILLE	6	415	20	Dry	Tangential	11,700	0.30	22	0	100	0	1,413
CT	CONNECTICUT LIGHT & POWER CO	NORWALK HARBOR	1	163	31	Dry	Tangential	10,500	0.30	57	0	100	0	1,285
CT	CONNECTICUT LIGHT & POWER CO	NORWALK HARBOR	2	172	28	Dry	Tangential	9,900	0.30	69	0	100	0	1,548
CT	UNITED ILLUMINATING CO	BRIDGEPORT HARBOR	1	82	34	Dry	Cyclone	10,200	0.50	55	0	100	0	1,013
CT	UNITED ILLUMINATING CO	BRIDGEPORT HARBOR	2	170	30	Dry	Cyclone	10,100	0.50	58	0	100	0	2,181
CT	UNITED ILLUMINATING CO	ENGLISH	7	35	43	Dry	Vertical	13,200	0.30	5	0	100	0	32
CT	UNITED ILLUMINATING CO	ENGLISH	8	37	40	Dry	Vertical	12,200	0.30	8	0	100	0	47
CT	UNITED ILLUMINATING CO	NEW HAVEN HARBOR	* 1	447	16	Dry	Tangential	9,400	0.30	72	0	88	12	3,984
MA	BOSTON EDISON CO	MYSTIC	4	135	34	Dry	Tangential	10,000	0.30	57	0	100	0	1,018
MA	BOSTON EDISON CO	MYSTIC	5	135	32	Dry	Tangential	10,000	0.30	59	0	100	0	1,050
MA	BOSTON EDISON CO	MYSTIC	6	149	30	Dry	Tangential	10,000	0.30	45	0	100	0	888
MA	BOSTON EDISON CO	MYSTIC	7	585	16	Dry	Tangential	10,000	0.20	59	0	50	50	3,011
MA	BOSTON EDISON CO	NEW BOSTON	1	388	26	Dry	Opposed	10,000	0.50	52	0	81	19	4,413
MA	BOSTON EDISON CO	NEW BOSTON	2	388	24	Dry	Opposed	10,000	0.50	64	0	75	25	5,477
MA	CAMBRIDGE ELECTRIC LIGHT CO	BLACKSTONE STREET	* 5	380	42	Dry	Wall	10,000	0.24	0	0	12	88	18
MA	CAMBRIDGE ELECTRIC LIGHT CO	BLACKSTONE STREET	* 6	380	42	Dry	Wall	10,000	0.33	1	0	48	52	43
MA	CAMBRIDGE ELECTRIC LIGHT CO	BLACKSTONE STREET	*11	144	28	Dry	Wall	10,000	0.32	3	0	44	56	51
MA	CAMBRIDGE ELECTRIC LIGHT CO	BLACKSTONE STREET	*12	617	28	Dry	Wall	10,000	0.29	1	0	40	60	53
MA	CAMBRIDGE ELECTRIC LIGHT CO	KENDALL SQUARE	3	30	37	Dry	Wall	10,000	0.28	68	0	24	76	249
MA	CAMBRIDGE ELECTRIC LIGHT CO	KENDALL SQUARE	* 1	20	42	Dry	Wall	10,000	0.48	63	0	16	84	267
MA	CAMBRIDGE ELECTRIC LIGHT CO	KENDALL SQUARE	* 2	20	42	Dry	Wall	10,000	0.48	72	0	21	79	304
MA	CANAL ELECTRIC CO	CANAL	1	569	23	Dry	Opposed	9,006	0.75	60	0	100	0	7,679
MA	CANAL ELECTRIC CO	CANAL	2	581	15	Dry	Opposed	9,743	0.30	52	0	100	0	5,187
MA	COMMONWEALTH ELECTRIC CO	CANNON STREET	1	25	44	Dry	Wall	10,000	0.41	22	0	26	74	98
MA	COMMONWEALTH ELECTRIC CO	CANNON STREET	2	25	44	Dry	Wall	10,000	0.41	22	0	26	74	98

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
MA	COMMONWEALTH ELECTRIC CO	CANNON STREET	* 3	34	41	Dry	Wall	10,000	0.27	44	0	28	72	175
MA	NEW ENGLAND POWER CO	BRAYTON POINT	4	450	17	Dry	Wall	10,700	0.30	46	0	100	0	2,930
MA	NEW ENGLAND POWER CO	SALEM HARBOR	4	450	19	Dry	Wall	10,600	0.50	59	0	100	0	6,145
MA	TAUNTON CITY OF	CLEARY FLOOD	*8 CA9	28	16	Dry	Wall	10,000	0.34	11	0	100	0	44
MA	WESTERN MASSACHUSETTS ELEC CO	WEST SPRINGFIELD	1	46	42	Dry	Tangential	13,800	0.25	14	0	100	0	96
MA	WESTERN MASSACHUSETTS ELEC CO	WEST SPRINGFIELD	2	50	39	Dry	Opposed	12,800	0.25	13	0	100	0	89
MA	WESTERN MASSACHUSETTS ELEC CO	WEST SPRINGFIELD	3	114	34	Dry	Opposed	11,000	0.25	60	0	44	56	819
ME	BANGOR HYDRO-ELECTRIC CO	GRAHAM STATION	5	27	27	Dry	Opposed	10,000	0.45	12	0	100	0	64
ME	CENTRAL MAINE POWER CO	WILLIAM F. WYMAN	1	50	34	Dry	Wall	10,000	0.34	20	0	100	0	146
ME	CENTRAL MAINE POWER CO	WILLIAM F. WYMAN	2	50	33	Dry	Wall	10,000	0.34	25	0	100	0	185
ME	CENTRAL MAINE POWER CO	WILLIAM F. WYMAN	3	114	26	Dry	Tangential	10,000	0.34	54	0	100	0	918
ME	CENTRAL MAINE POWER CO	WILLIAM F. WYMAN	4	632	13	Dry	Wall	10,000	0.21	34	0	100	0	1,990
NH	PUBLIC SERVICE CO OF NH	NEWINGTON	1	400	17	Dry	Tangential	10,900	0.46	54	0	100	0	4,719
NH	PUBLIC SERVICE CO OF NH	SCHILLER	3	25	42	Dry	Wall	17,500	0.43	16				130
NJ	ATLANTIC CITY ELECTRIC CO	B L ENGLAND	3	176	17	Dry	Tangential	10,000	0.40	50	0	100	0	1,542
NJ	ATLANTIC CITY ELECTRIC CO	DEEPWATER	* 1	82	33	Wet	Cyclone	10,000	0.44	39	0	22	78	618
NJ	JERSEY CENTRAL POWER&LIGHT CO	GILBERT	* 1, 2	45	61	N/R	Wall	10,000	0.01	9	0	28	72	2
NJ	JERSEY CENTRAL POWER&LIGHT CO	GILBERT	3	73	41	N/R	Tangential	10,000	0.40	21				94
NJ	JERSEY CENTRAL POWER&LIGHT CO	SAYREVILLE	* 2, 3	45	52	Dry	Wall	10,000	0.23	0	0	100	0	2
NJ	JERSEY CENTRAL POWER&LIGHT CO	SAYREVILLE	* 4	29	42	Dry	Vertical	10,000	0.22	10	0	4	96	27
NJ	JERSEY CENTRAL POWER&LIGHT CO	SAYREVILLE	* 5, 6	45	46	N/R	Vertical	10,000	0.53	6	0	1	99	66
NJ	JERSEY CENTRAL POWER&LIGHT CO	SAYREVILLE	* 7	110	37	N/R	Cyclone	10,000	0.49	19				256
NJ	JERSEY CENTRAL POWER&LIGHT CO	SAYREVILLE	* 8	115	33	N/R	Cyclone	10,000	0.49	30				375
NJ	JERSEY CENTRAL POWER&LIGHT CO	WERNER	4	60	38	N/R	Cyclone	10,000	0.46	21	0	100	0	255
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	BERGEN	1	325	32	Wet	Wall	10,580	1.08	44	0	6	94	7,216
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	BERGEN	2	325	31	Wet	Wall	10,776	1.08	34	0	5	95	5,728
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	BURLINGTON	7	205	36	Wet	Wall	12,228	0.47	10	0	100	0	518
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	HUDSON	1	455	26	Wet	Cyclone	11,713	0.68	21	0	10	90	3,395
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	KEARNY	7	157	38	Wet	Tangential	15,234	0.23	4	0	100	0	85
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	KEARNY	8	157	38	Wet	Tangential	13,511	0.23	7	0	95	0	160
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	LINDEN	2	260	34	Wet	Wall	12,019	0.44	12	0	100	0	707
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	LINDEN	4	93	19	Dry	Wall	11,240	0.44	15	0	100	0	696

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	LINDEN	* 11	87	34	Wet	Wall	11,240	0.44	22	0	100	0	1,009
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	LINDEN	* 12	87	34	Wet	Wall	11,240	0.44	12	0	100	0	563
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	LINDEN	* 13	87		Wet	Wall	11,240	0.44	27	0	100	0	1,208
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	SEWAREN	1	111	43	Wet	Tangential	15,279	0.19	5	0	12	88	77
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	SEWAREN	2	108	43	Wet	Tangential	13,134	0.19	20	0	6	94	235
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	SEWAREN	3	116	42	Wet	Tangential	14,091	0.19	12	0	10	90	163
NJ	PUBLIC SERVICE ELECTRIC&GAS CO	SEWAREN	4	127	40	Wet	Tangential	12,280	0.19	24	0	11	89	411
NY	CENTRAL HUDSON GAS & ELEC CORP	DANSKAMMER	1	60	40	Dry	Tangential	9,464	0.24	64	0	27	73	384
NY	CENTRAL HUDSON GAS & ELEC CORP	DANSKAMMER	2	60	37	Dry	Tangential	9,464	0.24	73	0	26	74	434
NY	CENTRAL HUDSON GAS & ELEC CORP	ROSETON	1	600	17	Dry	Tangential	9,185	0.48	58	0	100	0	6,672
NY	CENTRAL HUDSON GAS & ELEC CORP	ROSETON	2	540	17	Dry	Tangential	9,185	0.44	60	0	100	0	5,749
NY	CONSOLIDATED EDISON CO OF NY	59TH STREET	* 110	72	39	Dry	Wall	9,650	0.38	1	0	100	0	11
NY	CONSOLIDATED EDISON CO OF NY	59TH STREET	* 111	50	41	Dry	Wall	9,650	0.41	29	0	100	0	251
NY	CONSOLIDATED EDISON CO OF NY	59TH STREET	* 112	38		Dry	Wall	10,779	0.44	34	0	100	0	268
NY	CONSOLIDATED EDISON CO OF NY	59TH STREET	* 113	47		Dry	Wall	9,650	0.41	28	0	100	0	225
NY	CONSOLIDATED EDISON CO OF NY	59TH STREET	* 114	73		Dry	Tangential	9,650	0.22	36	0	100	0	244
NY	CONSOLIDATED EDISON CO OF NY	59TH STREET	* 115	73		Dry	Tangential	9,650	0.22	33	0	100	0	224
NY	CONSOLIDATED EDISON CO OF NY	74TH STREET	* 120	58	35	No data	Tangential	9,650	0.30	40	0	100	0	288
NY	CONSOLIDATED EDISON CO OF NY	74TH STREET	* 121	57	29	No data	Tangential	9,650	0.30	41	0	100	0	291
NY	CONSOLIDATED EDISON CO OF NY	74TH STREET	* 122	58	32	No data	Tangential	9,650	0.30	40	0	100	0	288
NY	CONSOLIDATED EDISON CO OF NY	ARTHUR KILL	20	350	32	Dry	Wall	9,650	0.33	20	0	100	0	967
NY	CONSOLIDATED EDISON CO OF NY	ARTHUR KILL	30	501	22	Dry	Tangential	9,300	0.25	28	0	100	0	1,451
NY	CONSOLIDATED EDISON CO OF NY	ASTORIA	10	175	38	Dry	Opposed	9,950	0.28	31	0	33	67	672
NY	CONSOLIDATED EDISON CO OF NY	ASTORIA	20	173	37	Dry	Opposed	9,950	0.27	57	0	28	72	1,155
NY	CONSOLIDATED EDISON CO OF NY	ASTORIA	30	361	33	Dry	Opposed	9,650	0.31	51	0	32	68	2,436
NY	CONSOLIDATED EDISON CO OF NY	ASTORIA	40	375	30	Dry	Tangential	9,530	0.17	20	0	58	42	533
NY	CONSOLIDATED EDISON CO OF NY	ASTORIA	50	375	29	Dry	Tangential	9,560	0.17	41	0	44	56	1,117
NY	CONSOLIDATED EDISON CO OF NY	EAST RIVER	50	164	40	Dry	Opposed	10,230	0.23	46	0	98	2	767
NY	CONSOLIDATED EDISON CO OF NY	EAST RIVER	60	156	40	Dry	Opposed	9,987	0.29	60	0	57	43	1,193
NY	CONSOLIDATED EDISON CO OF NY	EAST RIVER	70	175	36	Dry	Wall	9,950	0.35	21	0	38	62	560
NY	CONSOLIDATED EDISON CO OF NY	HUDSON AVENUE	100	178	40	Dry	Wall	12,421	0.47	46	0	100	0	2,094
NY	CONSOLIDATED EDISON CO OF NY	RAVENSWOOD	10	390	29	Dry	Tangential	9,550	0.22	44	0	24	76	1,585
NY	CONSOLIDATED EDISON CO OF NY	RAVENSWOOD	20	390	28	Dry	Tangential	9,550	0.25	38	0	26	74	1,570
NY	CONSOLIDATED EDISON CO OF NY	RAVENSWOOD	30	972	26	Dry	Tangential	9,590	0.25	35	0	50	50	3,555

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 41	48	43	No data	Tangential	9,650	0.18	29	0	47	53	107
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 42	48	42	No data	Tangential	9,650	0.18	29	0	47	53	107
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 51	65	54	No data	Tangential	9,650	0.18	28	0	35	65	137
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 52	70	53	No data	Tangential	9,650	0.18	27	0	38	62	142
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 61	89	50	No data	Tangential	10,220	0.18	25	0	34	66	176
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 62	87	50	No data	Tangential	9,650	0.17	18	0	10	90	112
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 80	126	42	No data	Tangential	10,230	0.16	52	0	26	74	455
NY	CONSOLIDATED EDISON CO OF NY	WATERSIDE	* 90	128	42	No data	Tangential	10,070	0.14	67	0	23	77	529
NY	LONG ISLAND LIGHTING CO	E F BARRETT	1	185	35	Dry	Tangential	9,385	0.29	77	0	24	76	1,702
NY	LONG ISLAND LIGHTING CO	E F BARRETT	2	185	28	Dry	Tangential	9,385	0.32	75	0	23	77	1,803
NY	LONG ISLAND LIGHTING CO	FAR ROCKAWAY	4	114	38	Dry	Tangential	10,000	0.00	53	0	36	64	0
NY	LONG ISLAND LIGHTING CO	GLENWOOD	4	118	39	Dry	Tangential	10,200	0.23	34	0	24	76	412
NY	LONG ISLAND LIGHTING CO	GLENWOOD	5	118	37	Dry	Tangential	10,200	0.23	53	0	30	70	653
NY	LONG ISLAND LIGHTING CO	NORTHPORT	1	370	24	Dry	Tangential	9,360	0.30	65	0	100	0	2,960
NY	LONG ISLAND LIGHTING CO	NORTHPORT	2	370	23	Dry	Tangential	9,360	0.30	65	0	100	0	2,962
NY	LONG ISLAND LIGHTING CO	NORTHPORT	3	370	19	Dry	Tangential	9,360	0.30	74	0	100	0	3,362
NY	LONG ISLAND LIGHTING CO	NORTHPORT	4	370	14	Dry	Tangential	9,360	0.30	64	0	100	0	2,890
NY	LONG ISLAND LIGHTING CO	PORT JEFFERSON	1	45	43	Dry	Tangential	9,385	0.36	27	0	100	0	179
NY	LONG ISLAND LIGHTING CO	PORT JEFFERSON	2	45	41	Dry	Tangential	9,385	0.36	29	0	100	0	193
NY	LONG ISLAND LIGHTING CO	PORT JEFFERSON	3	185	33	Dry	Tangential	9,385	0.36	63	0	100	0	1,737
NY	LONG ISLAND LIGHTING CO	PORT JEFFERSON	4	185	31	Dry	Tangential	9,385	0.36	66	0	100	0	1,800
NY	NIAGARA MOHAWK POWER CORP	ALBANY	1	97	38	Dry	Tangential	10,801	0.14	74	0	12	88	470
NY	NIAGARA MOHAWK POWER CORP	ALBANY	2	97	38	Dry	Tangential	10,656	0.14	42	0	12	88	267
NY	NIAGARA MOHAWK POWER CORP	ALBANY	3	97	37	Dry	Tangential	10,777	0.14	71	0	13	87	459
NY	NIAGARA MOHAWK POWER CORP	ALBANY	4	97	36	Dry	Tangential	10,905	0.14	55	0	14	86	363
NY	NIAGARA MOHAWK POWER CORP	OSWEGO	3	75	42	Dry	Vertical	12,616	0.53	6	0	0	100	141
NY	NIAGARA MOHAWK POWER CORP	OSWEGO	4	90	39	Wet	Vertical	11,916	0.70	18	0	100	0	604
NY	NIAGARA MOHAWK POWER CORP	OSWEGO	5	850	14	Dry	Wall	10,503	1.00	21	0	99	1	8,368
NY	NIAGARA MOHAWK POWER CORP	OSWEGO	6	850	10	Dry	Wall	11,339	0.27	18	0	99	1	2,033
NY	ORANGE & ROCKLAND UTILS INC	BOWLINE POINT	1	580	19	Dry	Tangential	9,881	0.22	40	0	77	23	2,239
NY	ORANGE & ROCKLAND UTILS INC	BOWLINE POINT	2	570	17	Dry	Opposed	9,240	0.21	51	0	38	62	2,483
NY	ORANGE & ROCKLAND UTILS INC	LOVETT	* 1	17	36	Dry	Wall	10,000	0.52	2	0	0	100	8
NY	ORANGE & ROCKLAND UTILS INC	LOVETT	* 2	20	36	Dry	Wall	10,000	0.52	4	0	6	94	19
NY	ORANGE & ROCKLAND UTILS INC	LOVETT	* 3	69	36	Dry	Wall	9,300	0.38	31	0	8	92	333
NY	ORANGE & ROCKLAND UTILS INC	LOVETT	4	198	25	Dry	Wall	9,963	1.40	27	5	20	75	3,238

* next to Boiler Unit indicates possible mismatch of EIA data with NURF Generator Unit

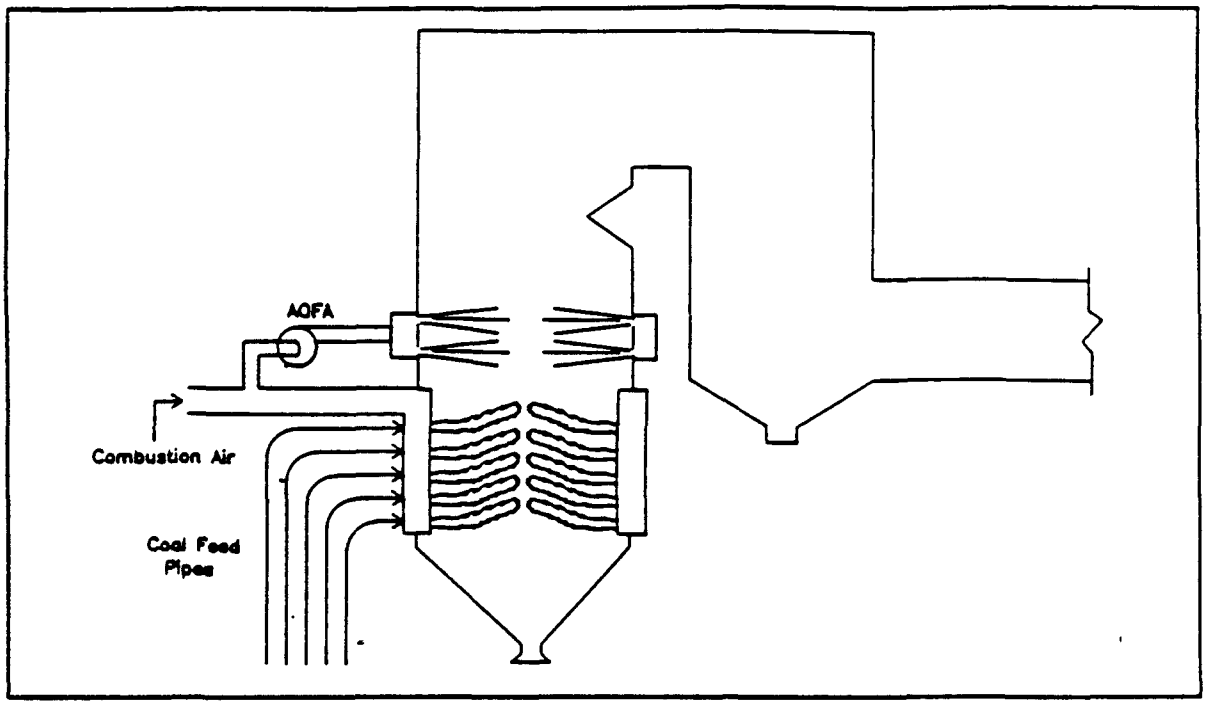
State	Utility	Plant	Unit NO.	Size (MW)	Years Old	Furnace	Firing Type	Heat Rate (Btu/KW-hr)	NOx (lb/MBtu)	CF (%)	COAL (%)	OIL (%)	GAS (%)	1987 NOx (Tons)
NY	POWER AUTHORITY OF STATE OF NY	CHARLES POLETTI	6	825	15	No data	Wall	10,000	0.25	43	0	38	62	3,845
RI	NEW ENGLAND POWER CO	MANCHESTER STREET	* 9	40	50	Dry	Wall	13,800	0.40	33	0	36	64	320
RI	NEW ENGLAND POWER CO	MANCHESTER STREET	*10	46	44	Dry	Wall	13,800	0.40	37	0	50	50	410
RI	NEW ENGLAND POWER CO	MANCHESTER STREET	*11	46	42	Dry	Wall	13,700	0.40	22	0	60	40	245
RI	NEW ENGLAND POWER CO	SOUTH STREET	* 121	48	73	Dry	Wall	10,000	0.45	68	0	47	53	645
RI	NEW ENGLAND POWER CO	SOUTH STREET	* 122	98	36	Dry	Wall	10,000	0.45	27	0	47	53	528
VT	BURLINGTON CITY OF	J C MCNEIL	1	50	7	Wet	Wall	10,000	0.28	3	0	100	0	20

TOTAL NOx EMISSIONS (Tons) FOR OIL/GAS UNITS = 176,266
TOTAL CAPACITY (MW) OF OIL/GAS UNITS = 27,883
TOTAL NUMBER OF OIL/GAS UNITS = 141

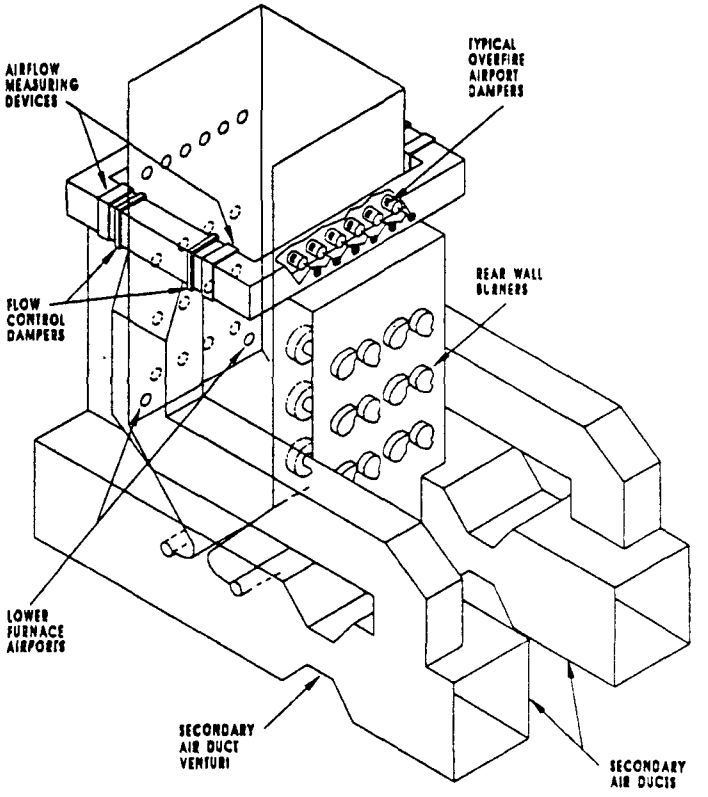
APPENDIX C

SCHEMATICS OF LOW-NO_x CONTROL EQUIPMENT AND OPERATION

C.1 OVERFIRE AIR SYSTEMS



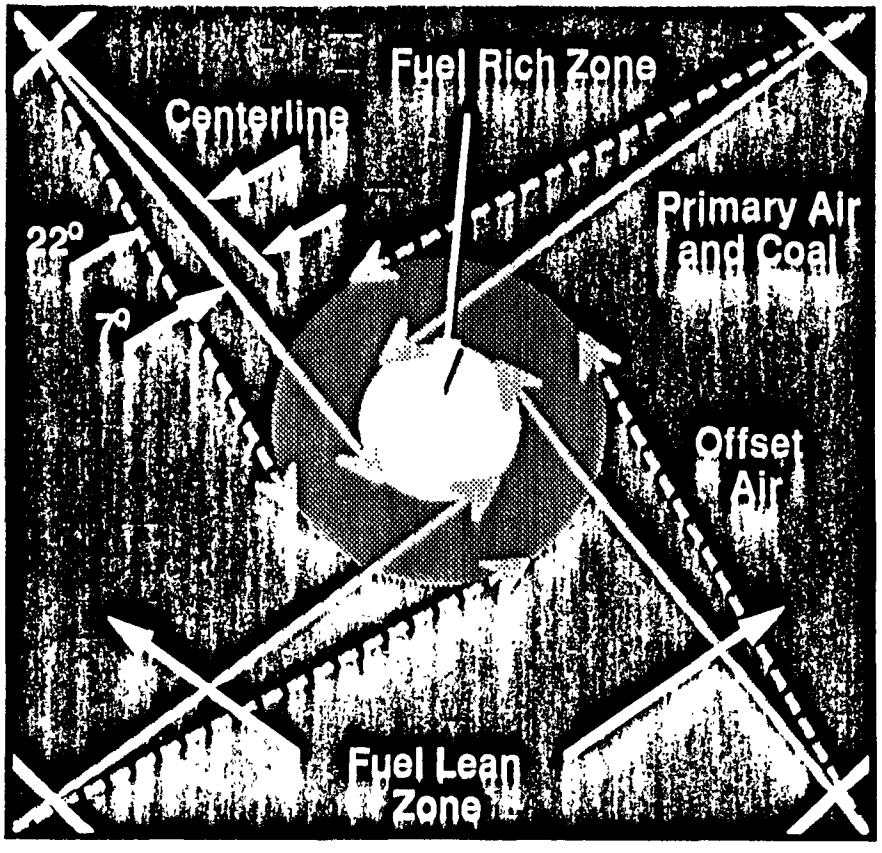
Advanced overfire air concept (Wilson, 1991)

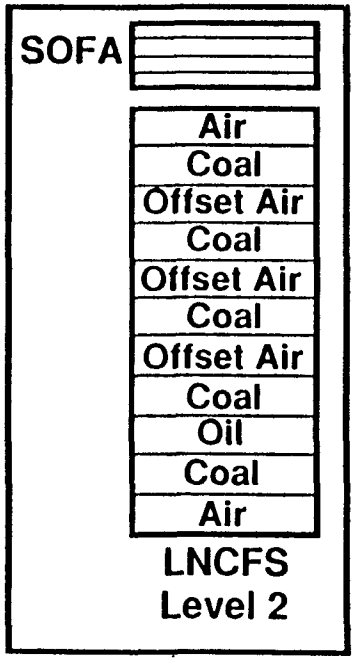


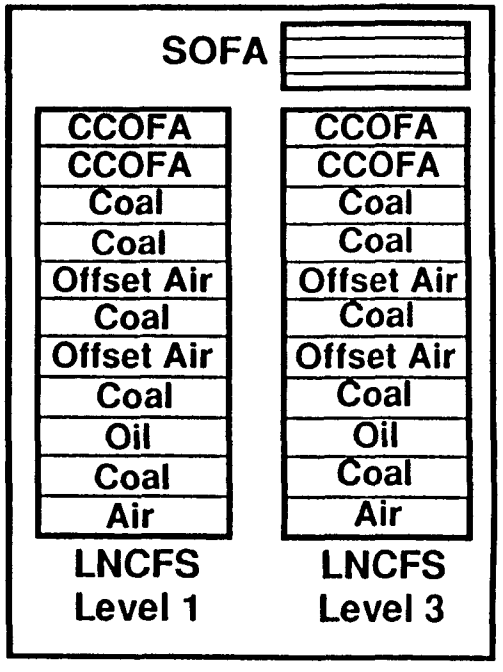
Typical advanced overfire air port system (Vatsky, 1991)

C.2 COAL-FIRED LOW-NO_x BURNERS

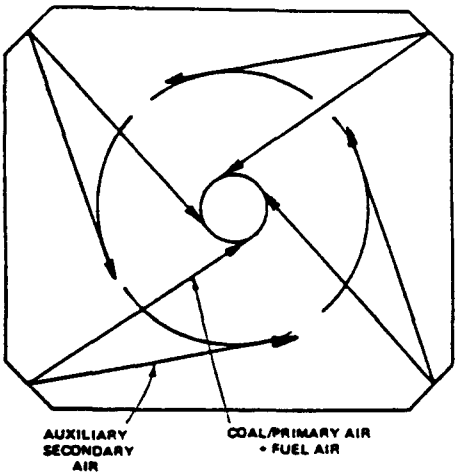
Tangentially-Fired Concentric Firing System



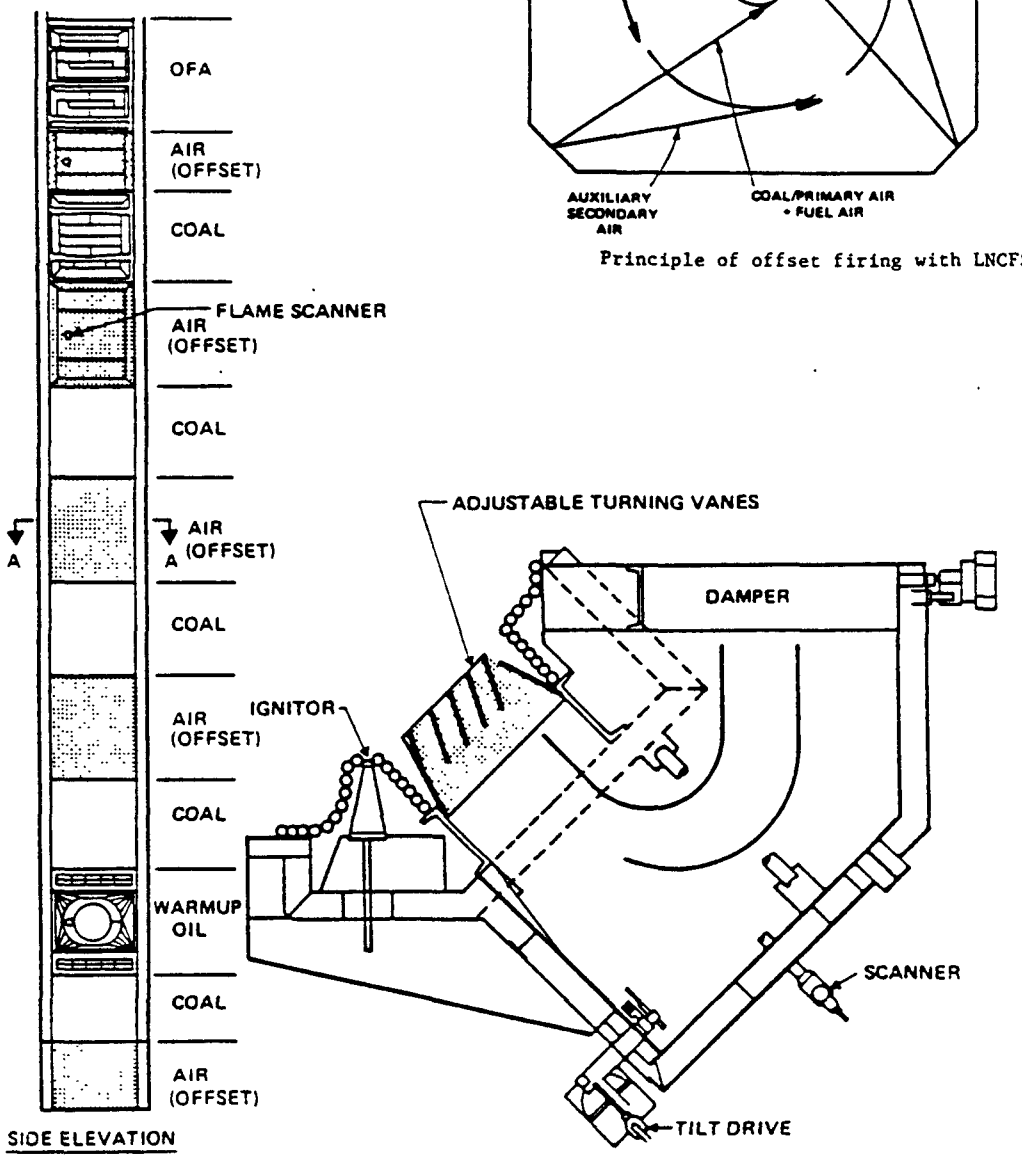




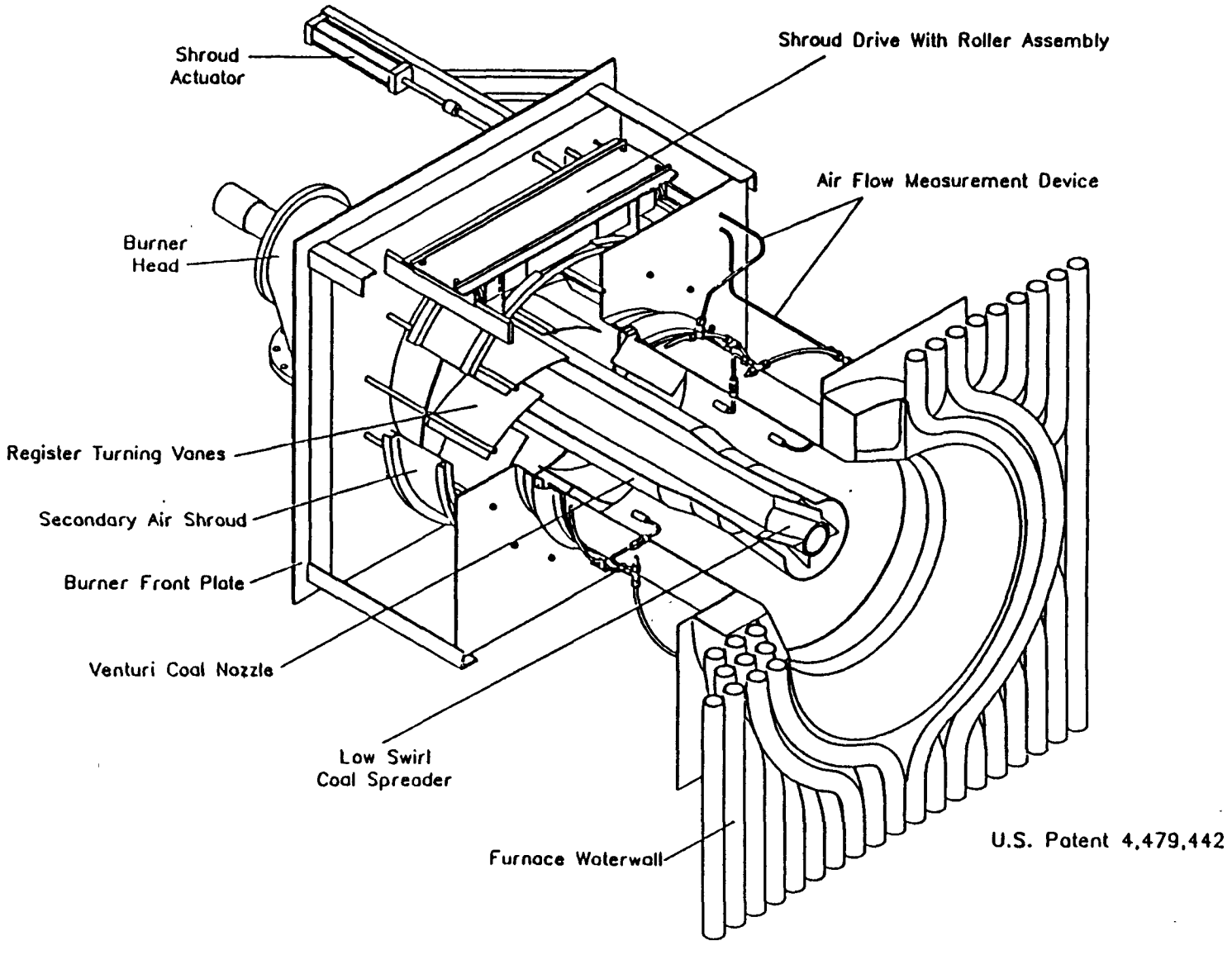
Low-NO_x concentric firing systems (Hardman, EPRI, 1992)



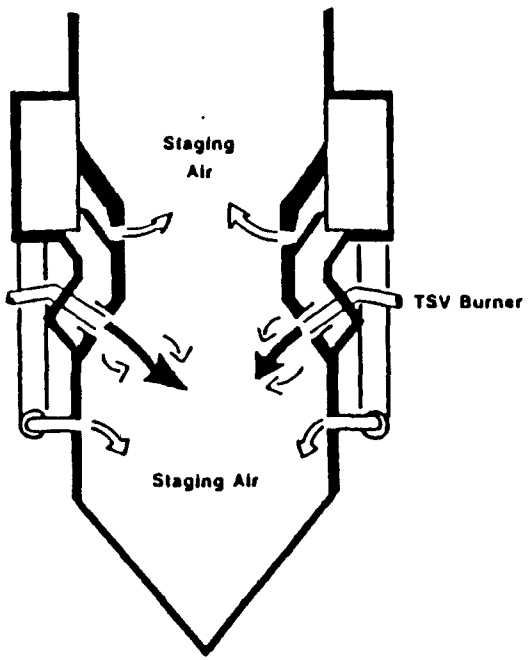
Principle of offset firing with LNCFS.



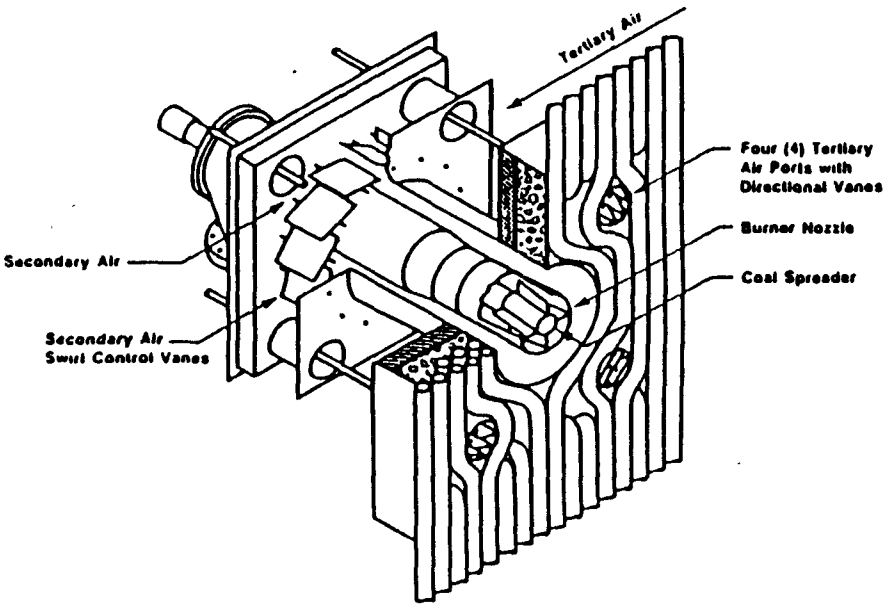
Low-NO_x concentric firing system (LNCFS) windbox modification arrangement at Hunter No. 2 (Kokkinos, et al., 1985)



Riley low NO_x controlled combustion venturi (CCV) burner for wall fired boilers

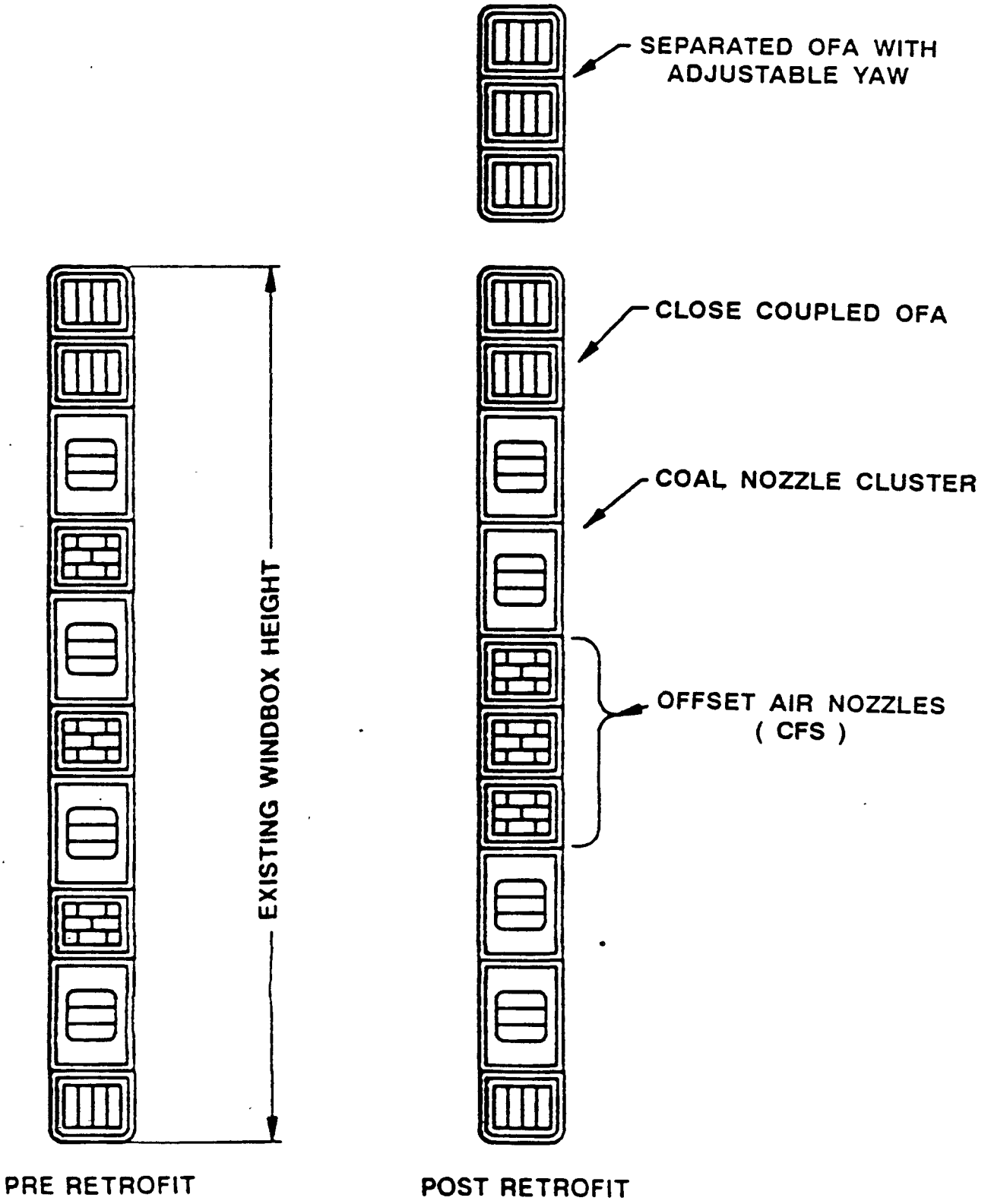


Advanced TURBO Furnace Staging System

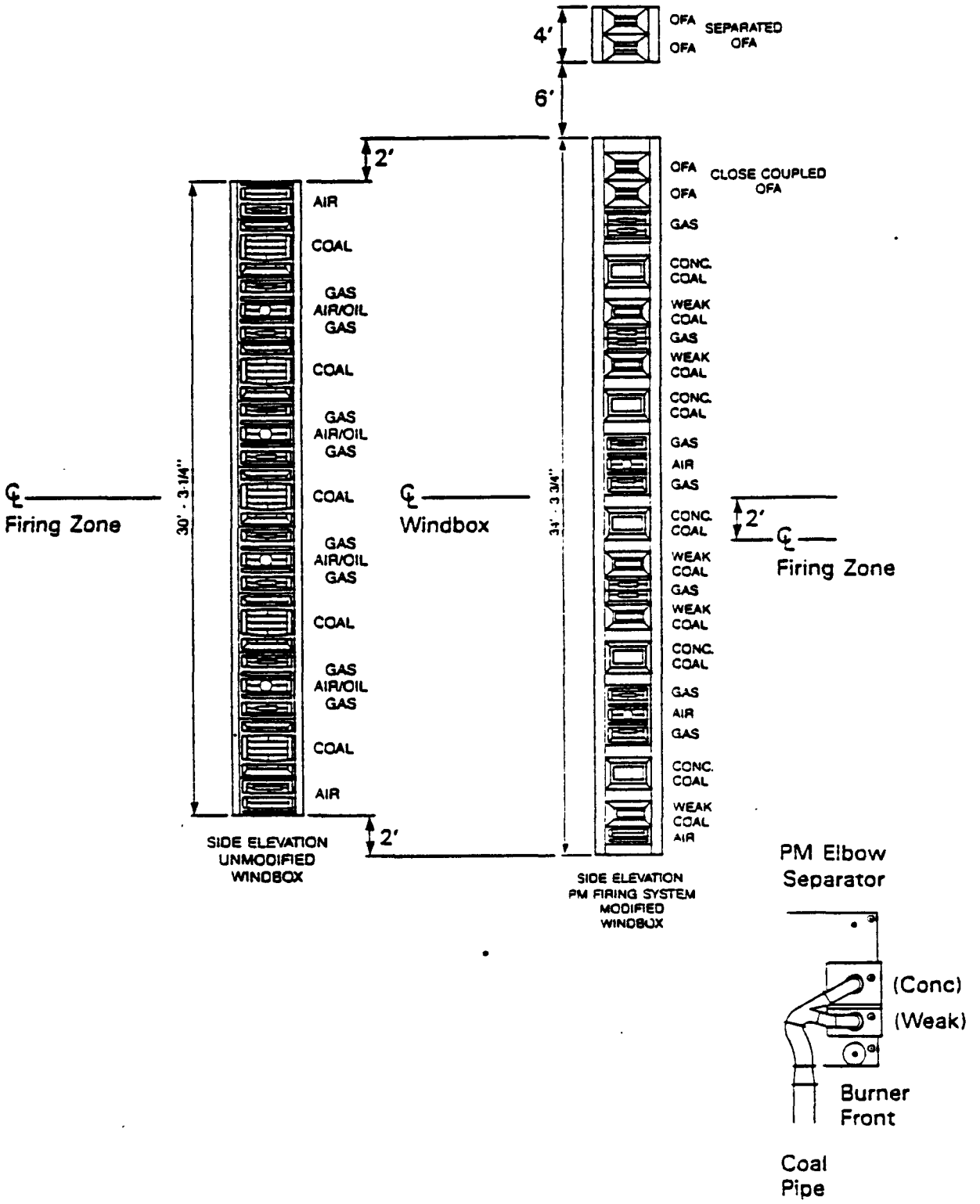


TSV Burner

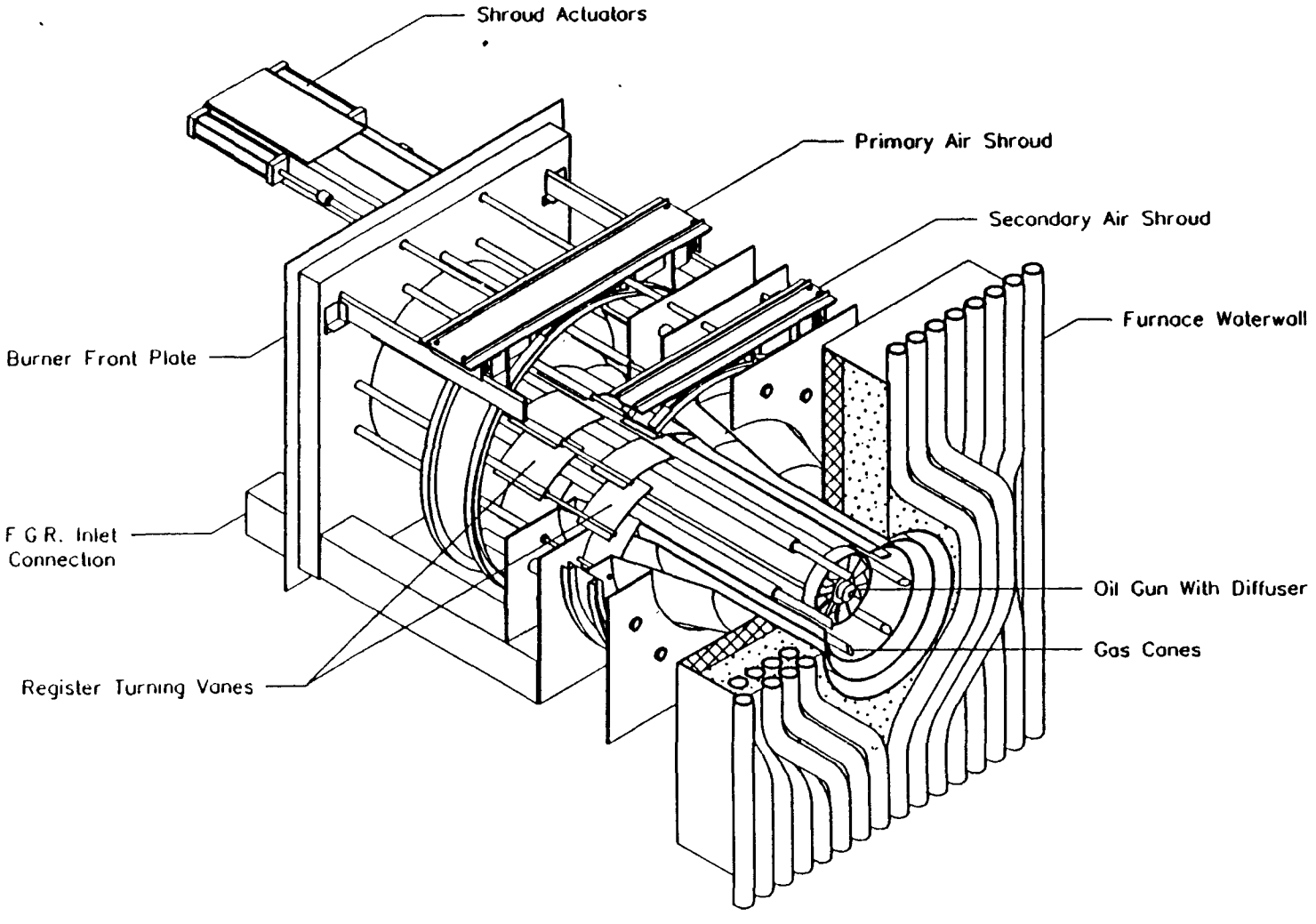
Riley Low NO_x TSV burner with advanced air staging for turbo-furnace, down fired and arch fired installation



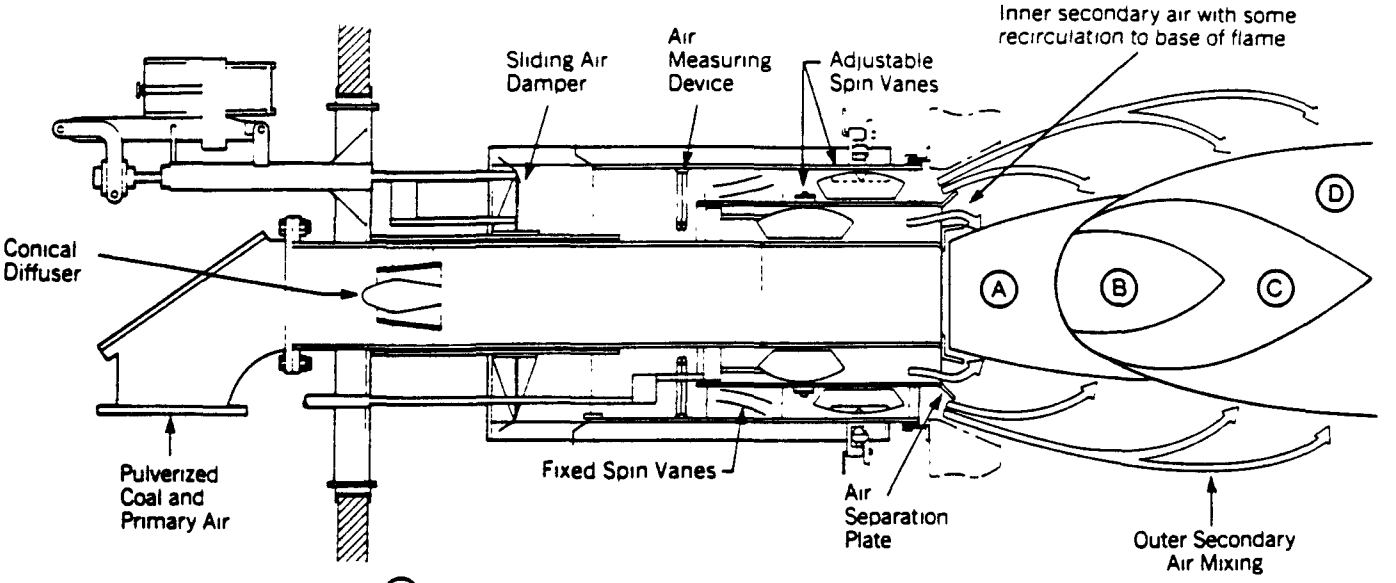
Concentric clustered tangential firing system (CCTFS) concept for low-NO_x retrofit applications (not commercially offered)



Schematic of Unmodified and PM modified windowboxes at Kansas Power & Light Lawrence Unit No. 5 (Lewis, et al., 1989)



Riley low-NO_x STS burner (Model 90) for windbox burner arrangements (Lisauskas, 1991)



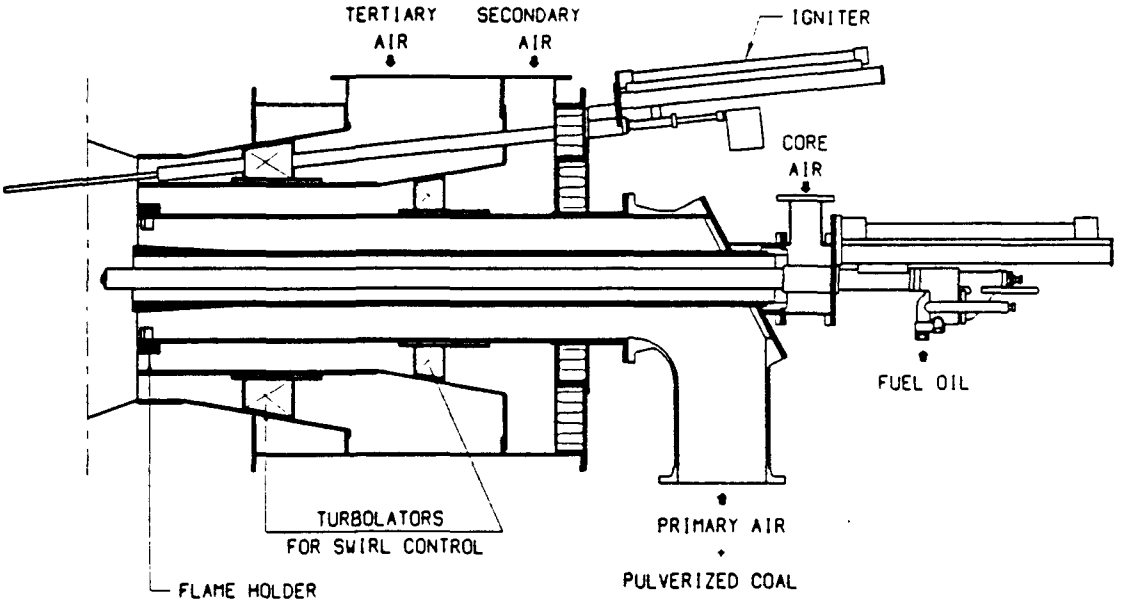
(A) High temperature - fuel rich devolatization zone

(B) Production of reducing species

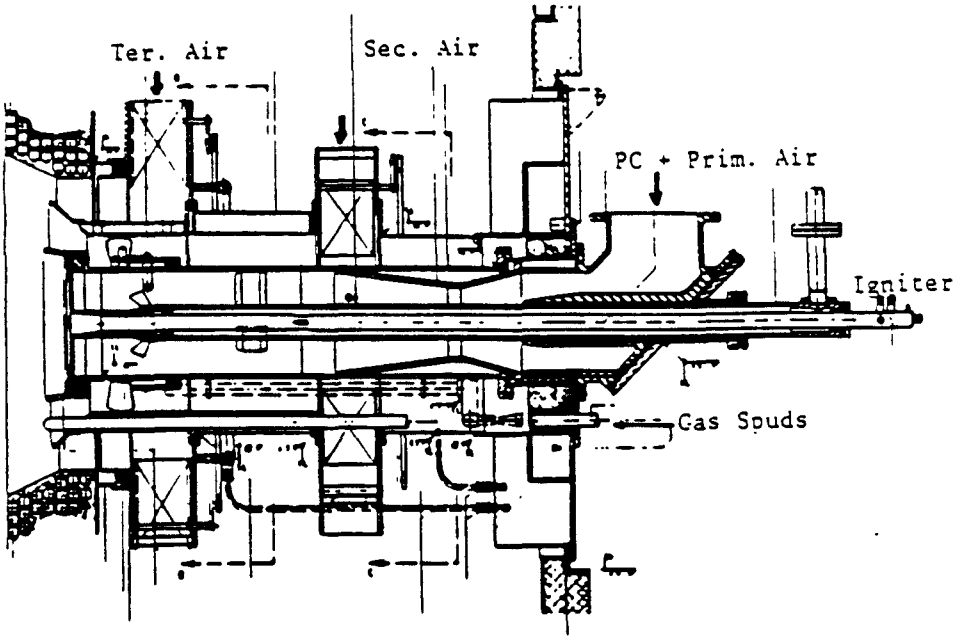
(C) NO_x decomposition zone

(D) Char oxidizing zone

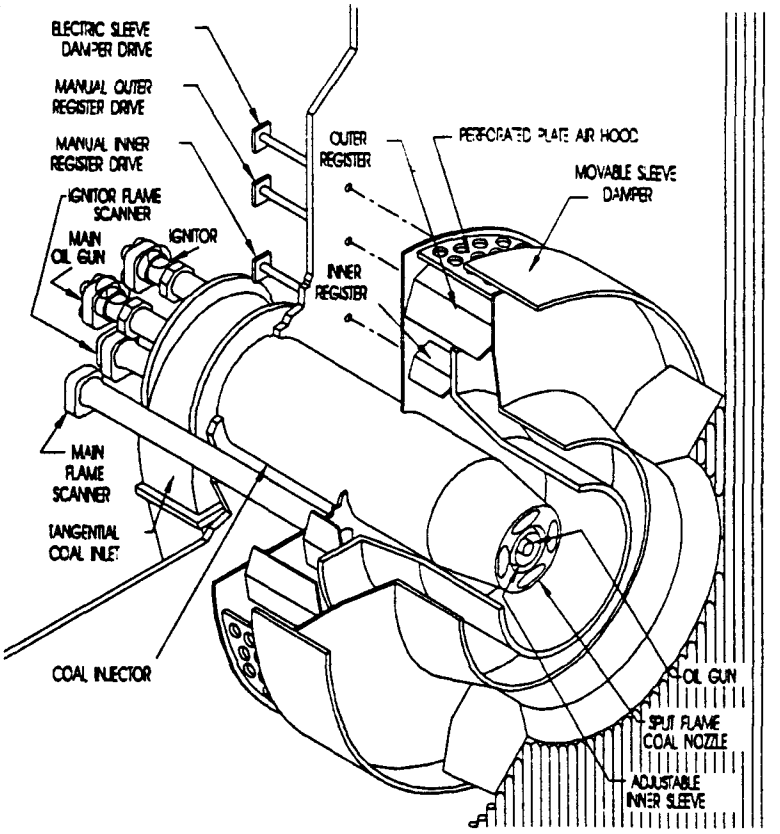
Babcock & Wilcox XCL burner with impeller (La Rue, 1990)



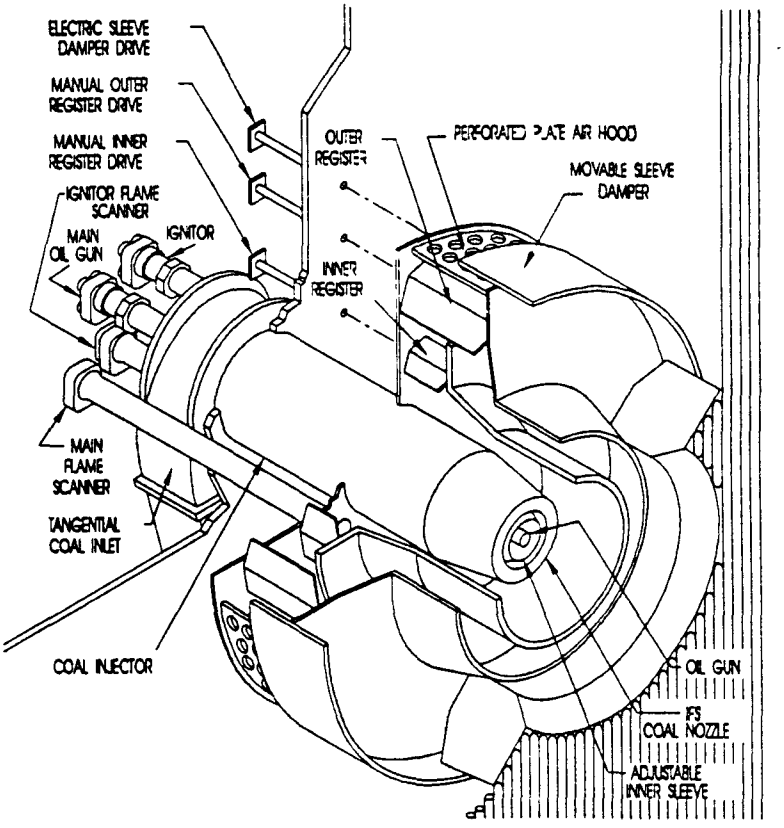
"BWE type 4 AF" attached flame low-NO_x burner (McCartney, 1991)



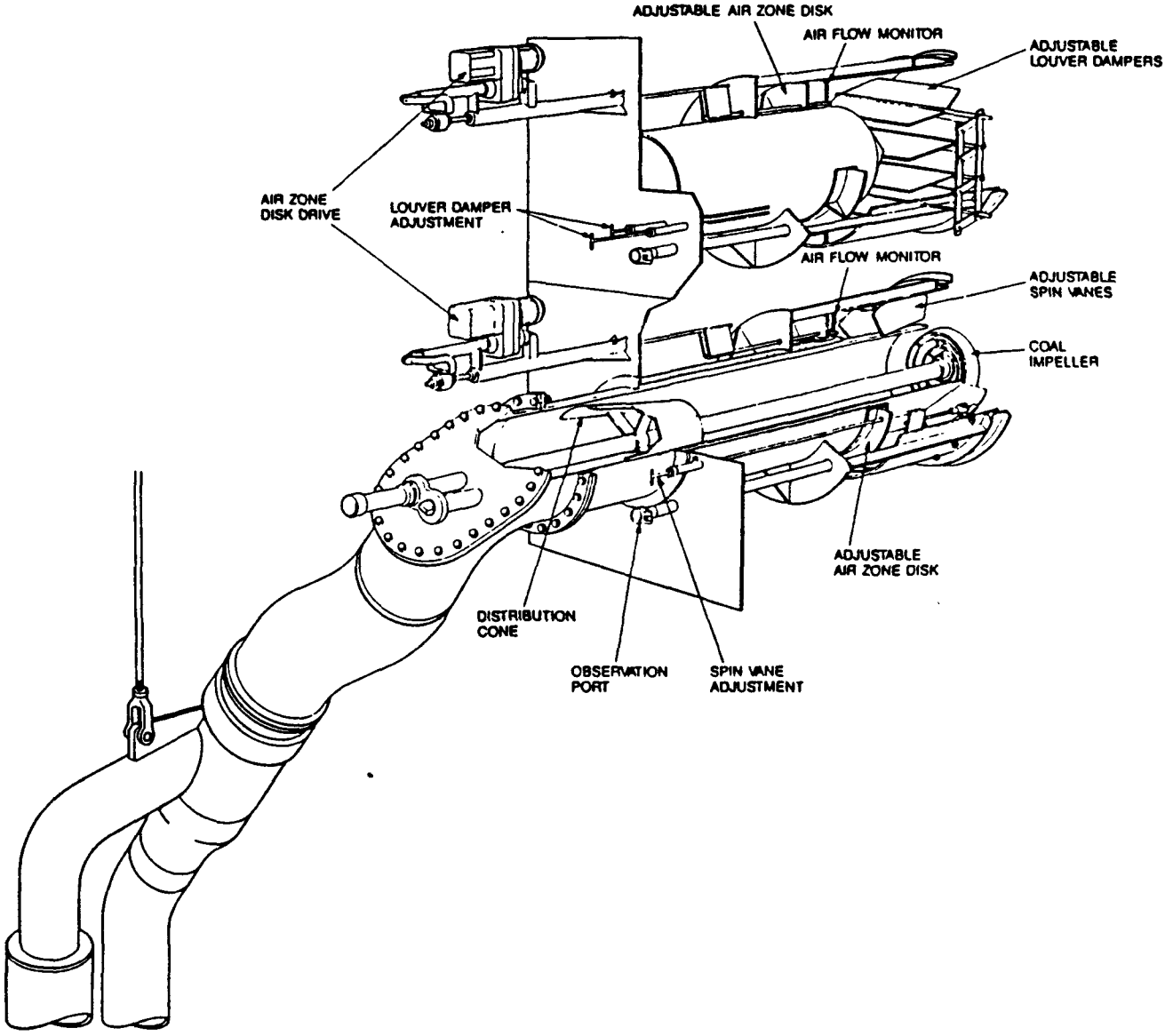
Modified HTNR burner for coal and gas firing (Van der Kooij, et al., 1991)



Controlled flow split flame burner (Vatsky, 1991)

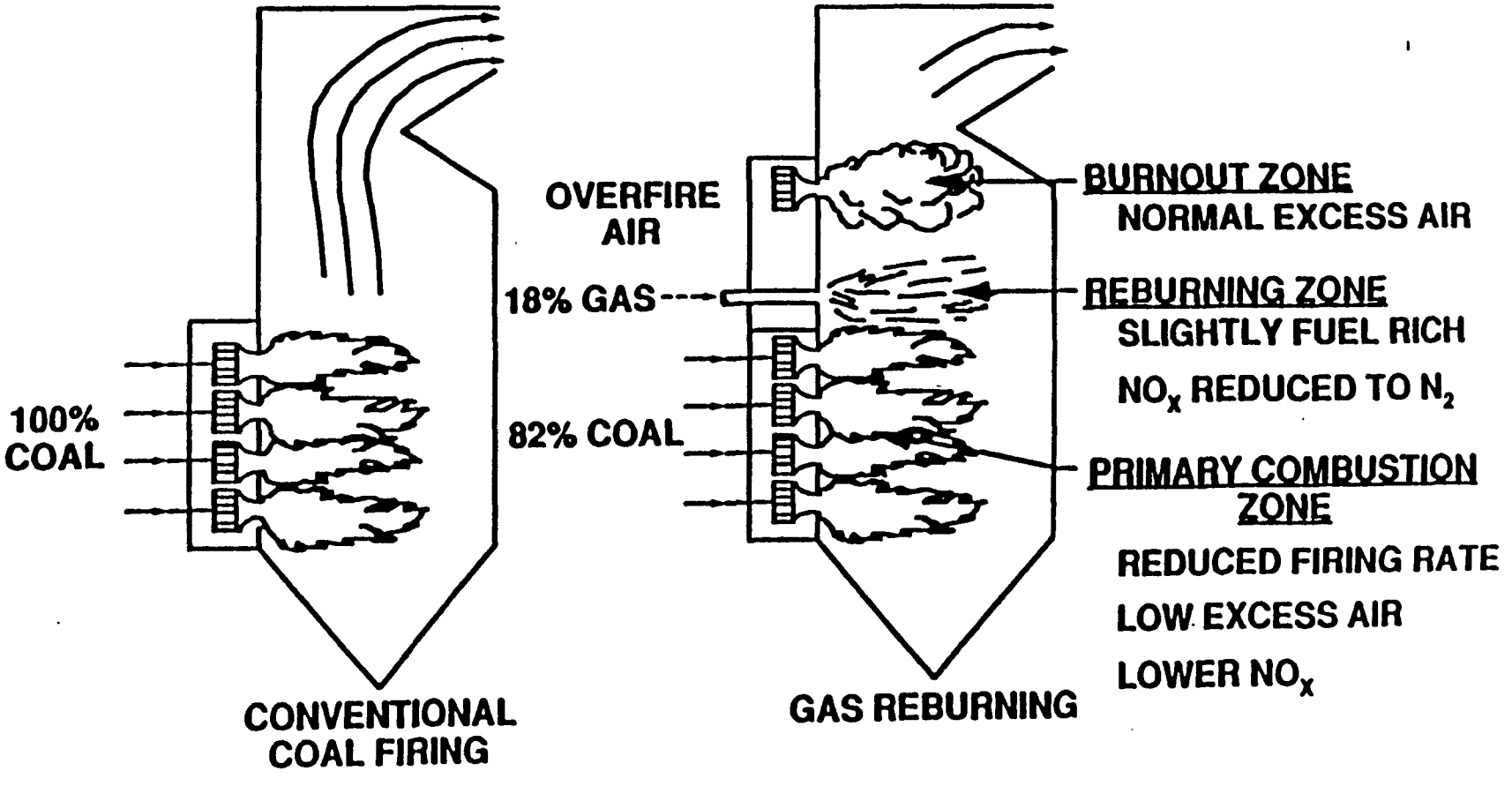


Internal Fuel Staged Low NO_x Burner™ (Vatsky, 1991)

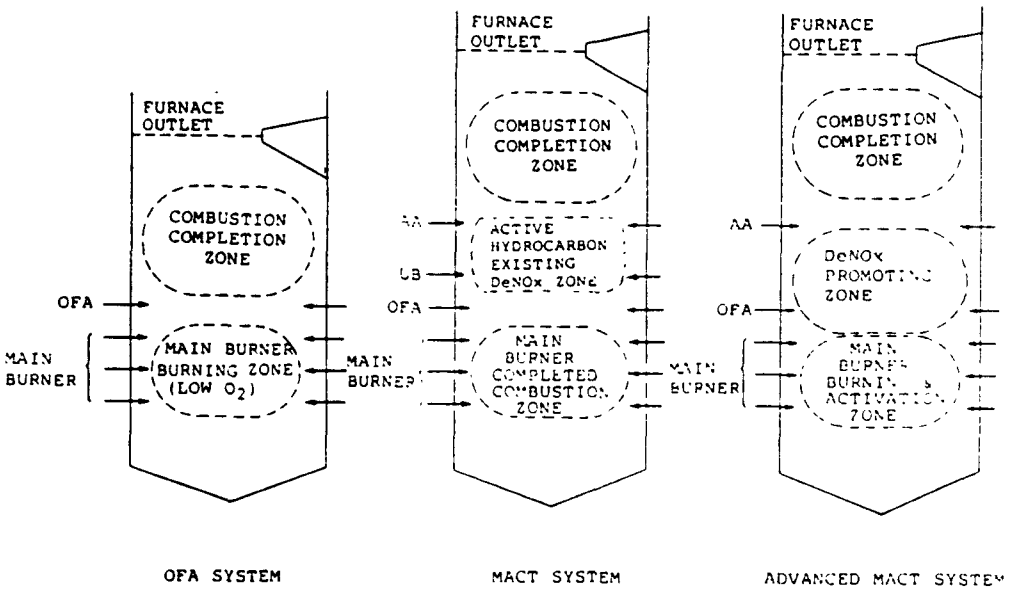


Low NO_x cell burner (LaRue, 1989)

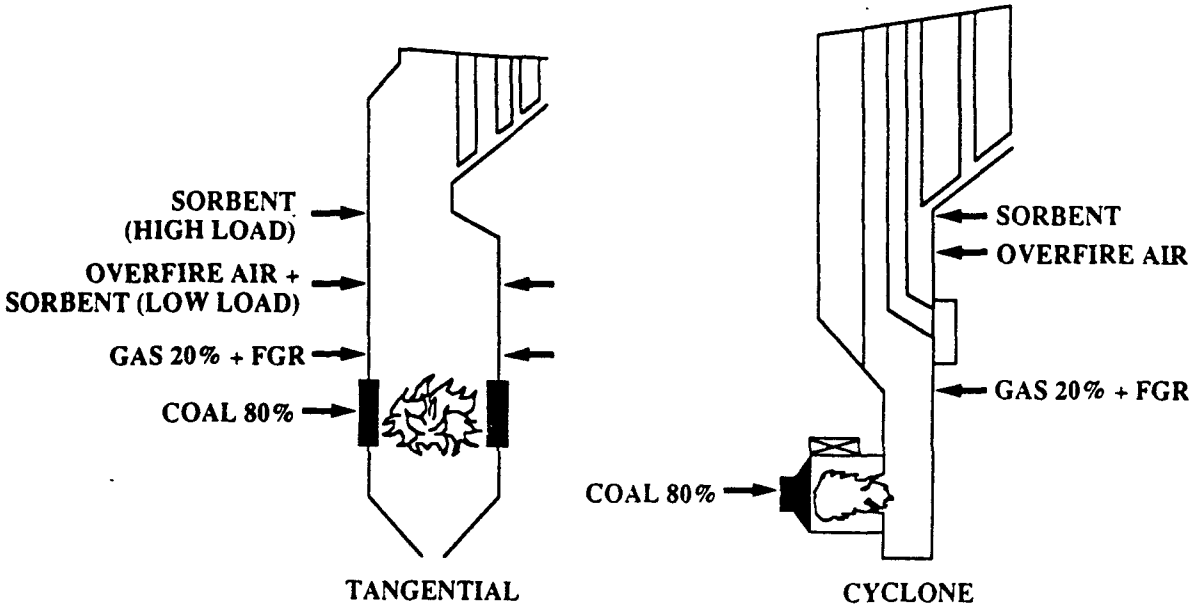
C.3 REBURNING OR FUEL STAGING ARRANGEMENTS



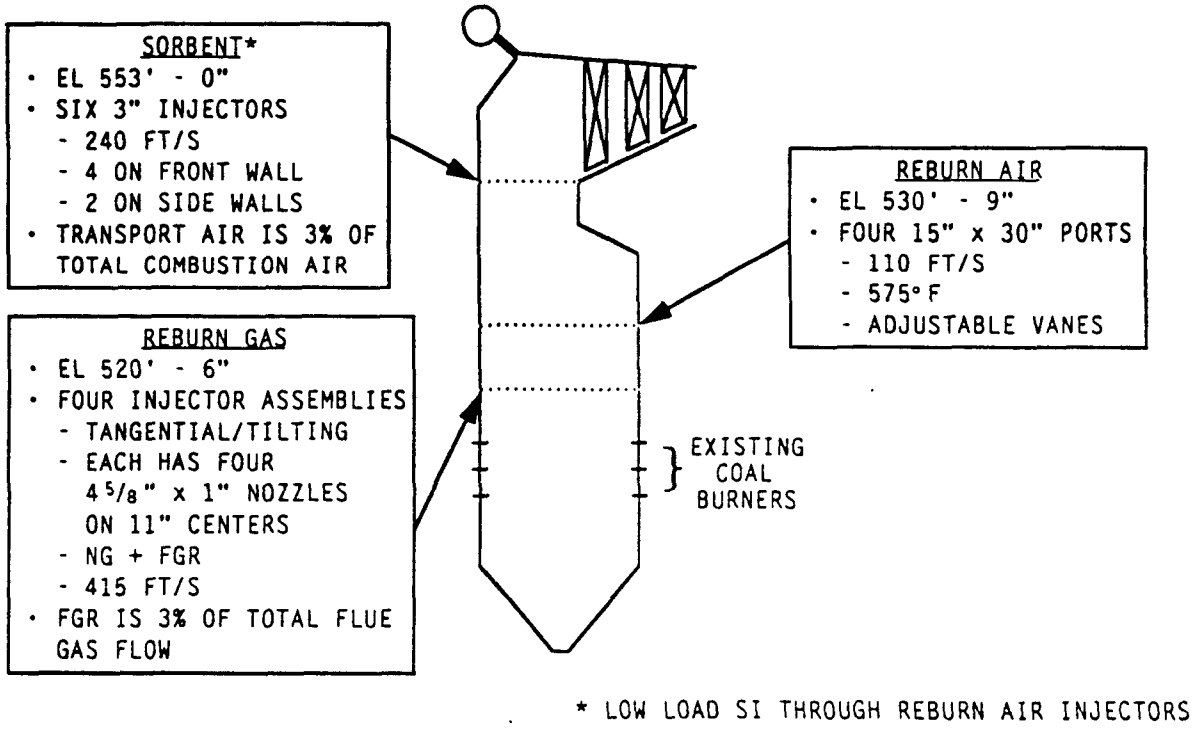
Application of gas reburning to a wall-fired boiler (EERC, 1991)



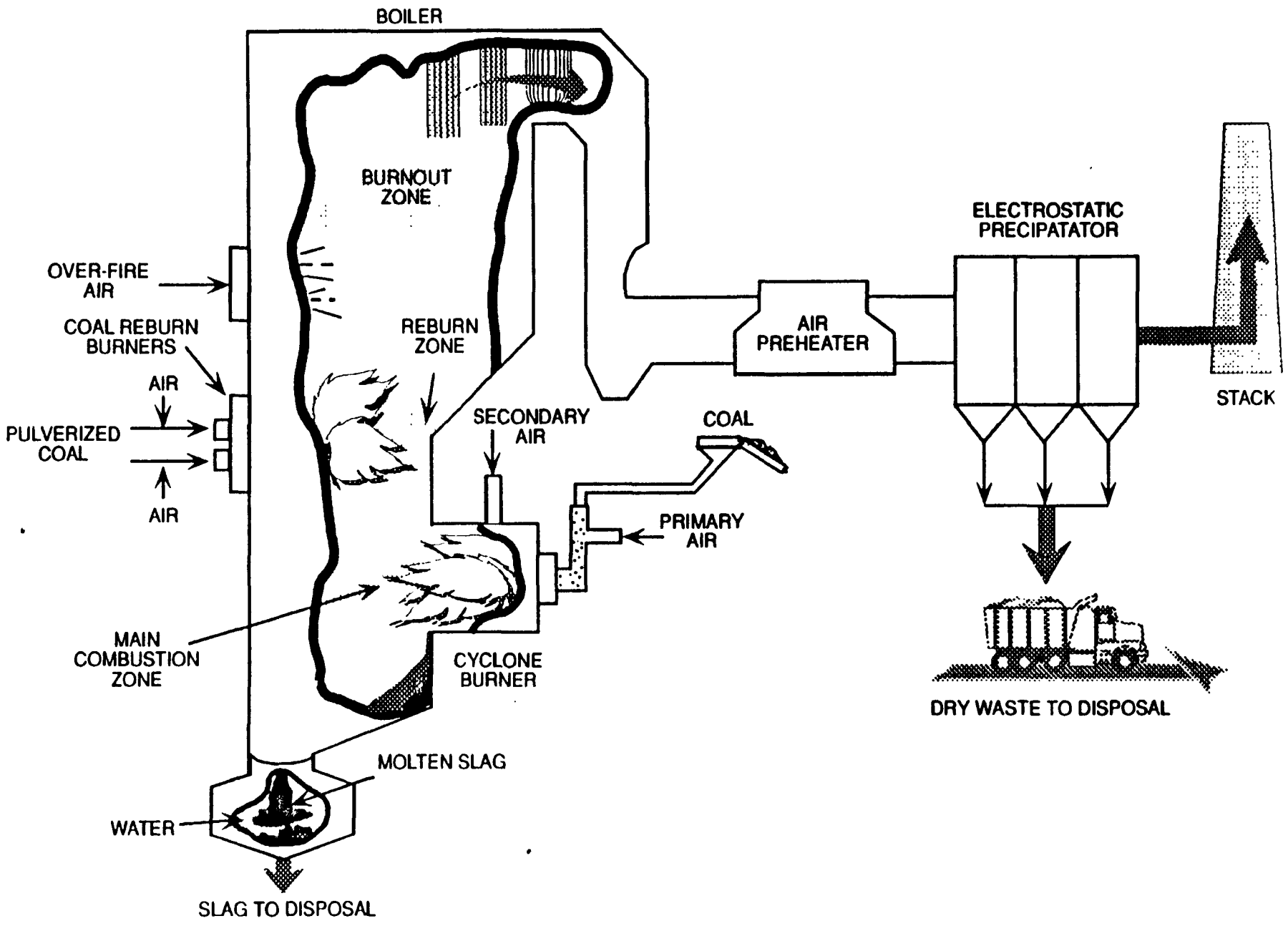
Principle of MACT (Araoka, 1987)



GR-SI configurations for two types of boilers (Bartok, et al., 1991)

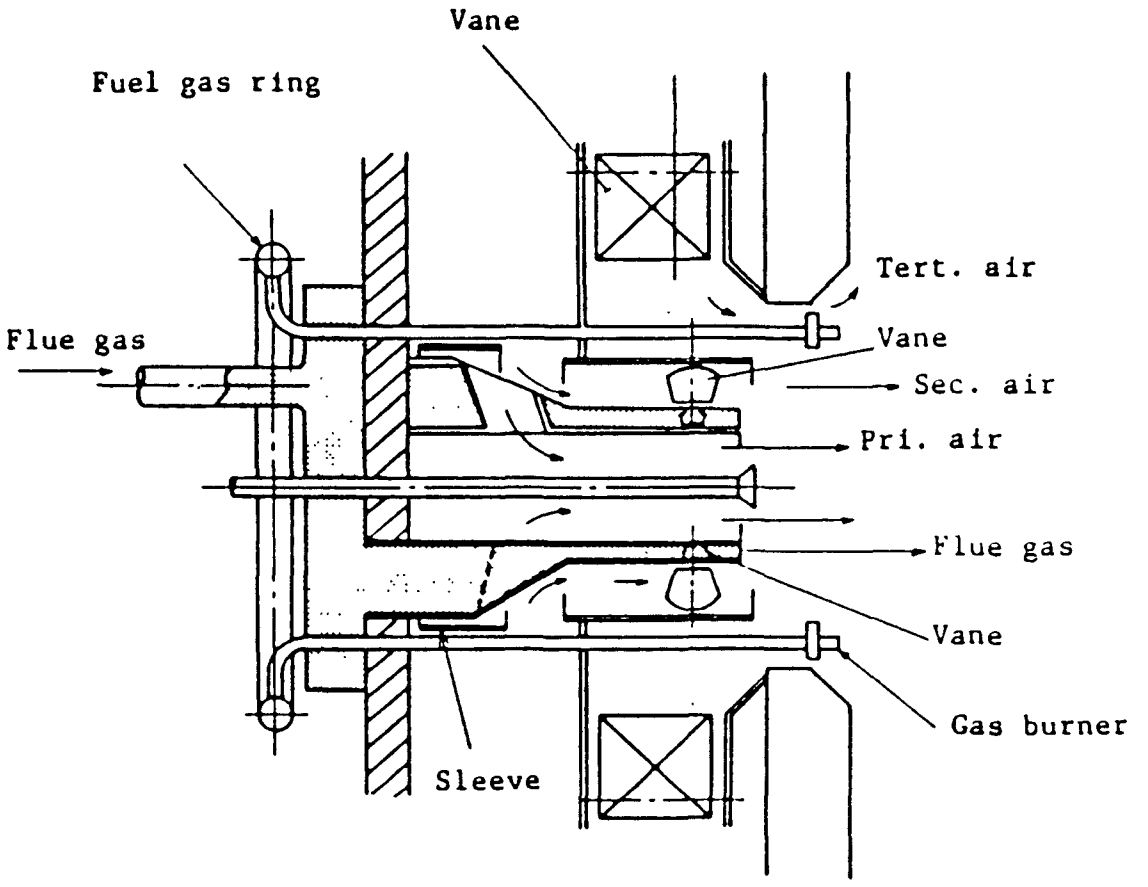


Summary of injector specifications for tangentially-fired boiler

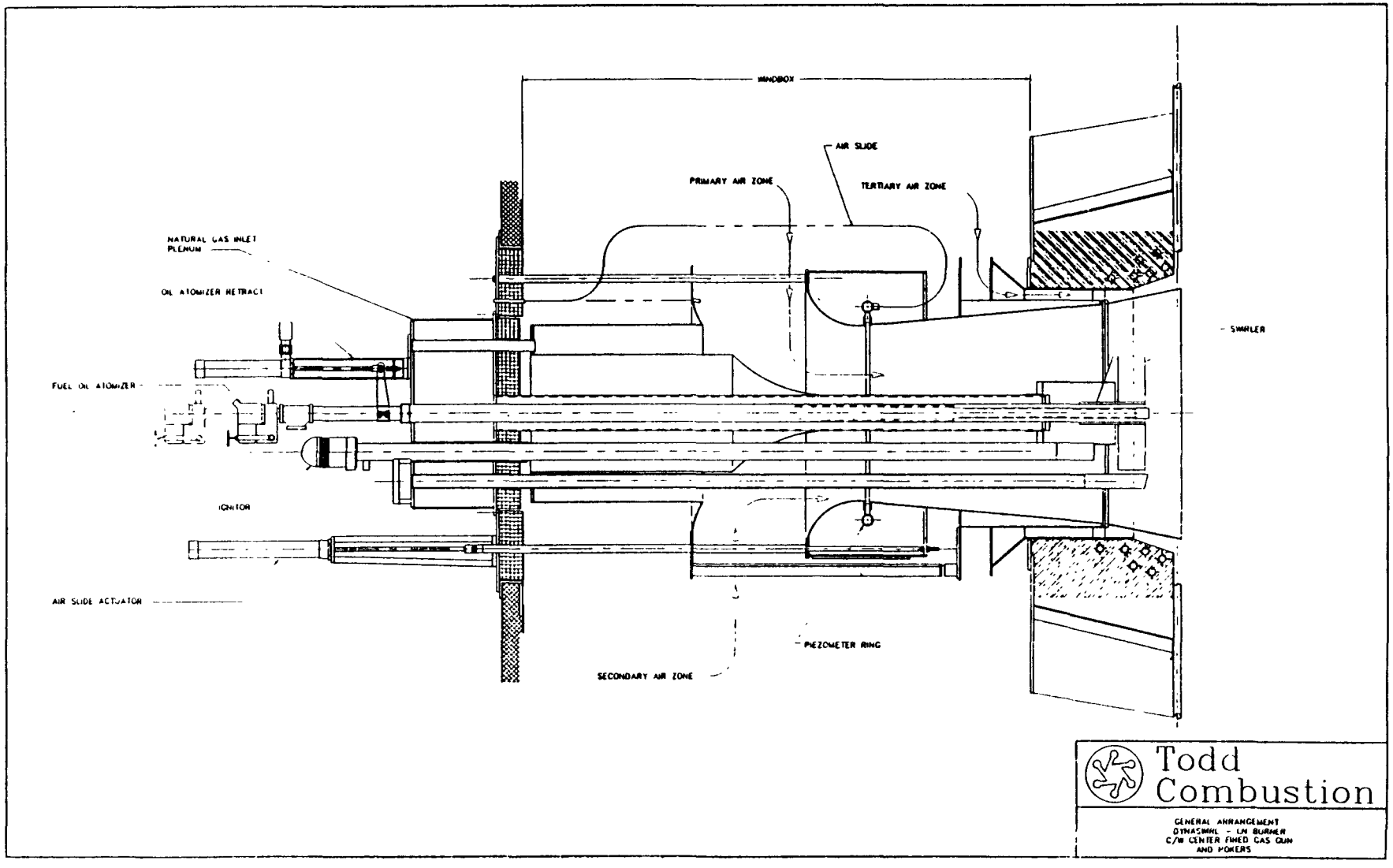


B&W coal reburn process schematic (Clean Coal Today, 1992)

C.4 OIL- AND GAS-FIRED BURNERS

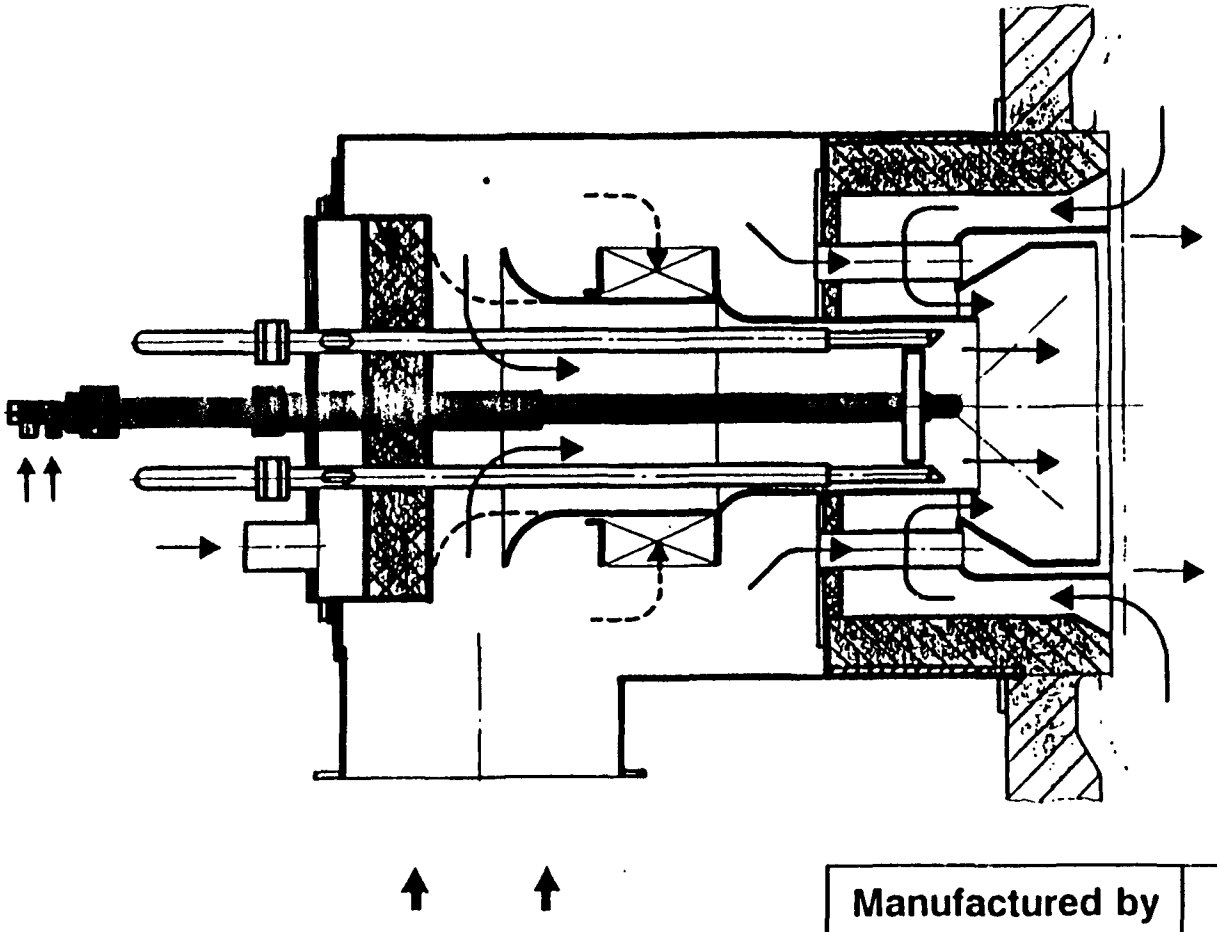


PG dual air register low-NO_x burner/OFA/FGR (BHK/B&W) (Pepper, et al., 1987)



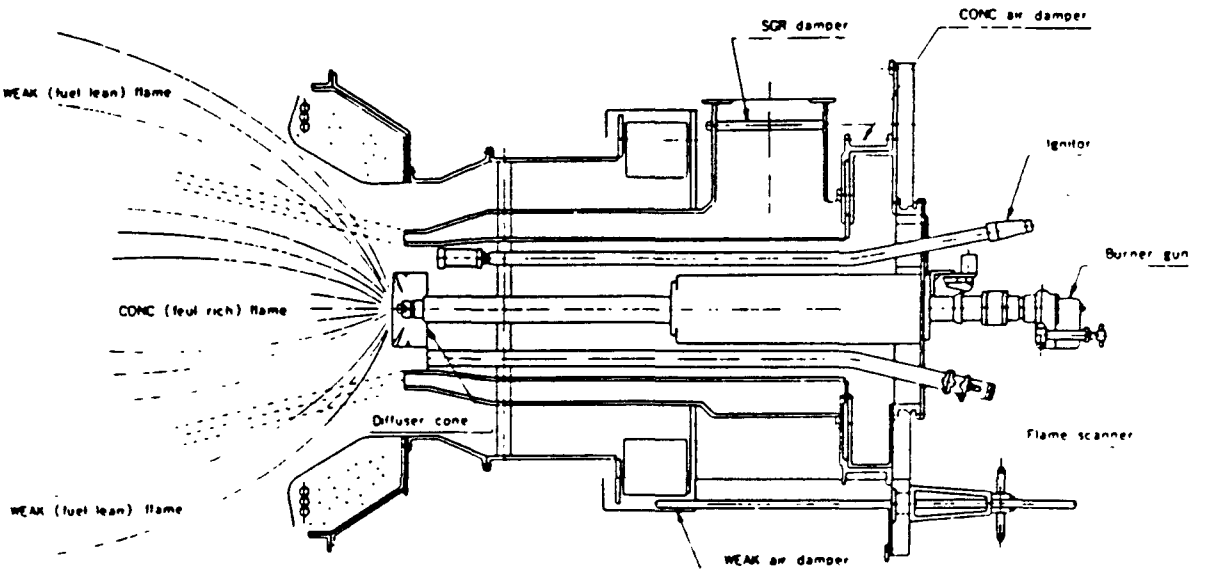
Todd Dynaswirl® low-NO_x burner (Bayard DeVolo, 1991)

Low NOx Technology

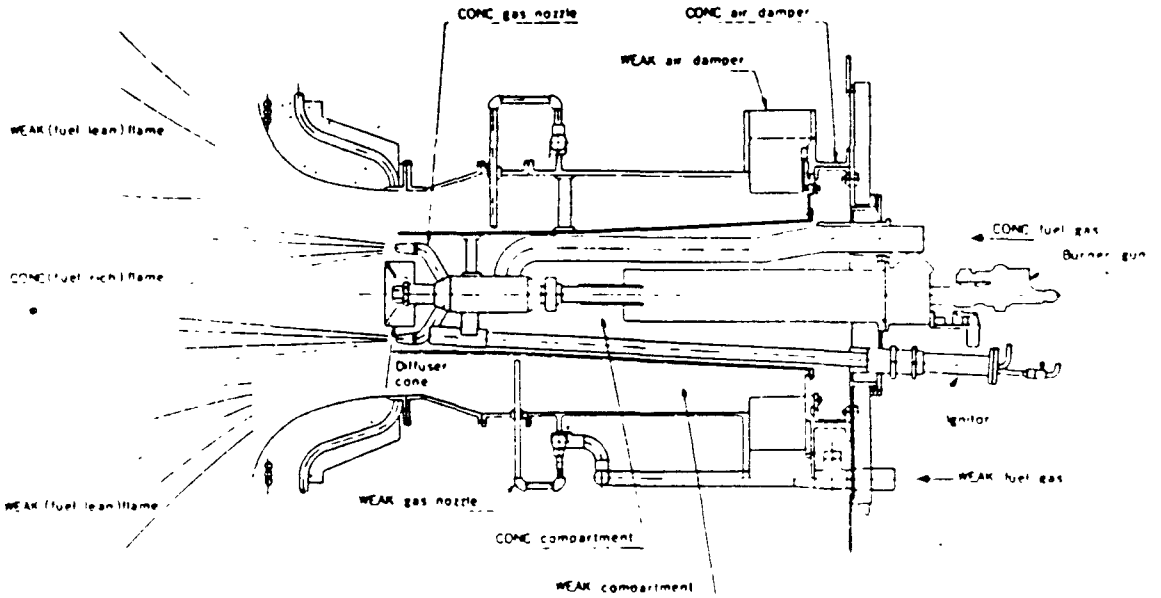


Manufactured by		Technology by
RILEY		Deutsche Babcock

ASR burner—axial staged return flow burner



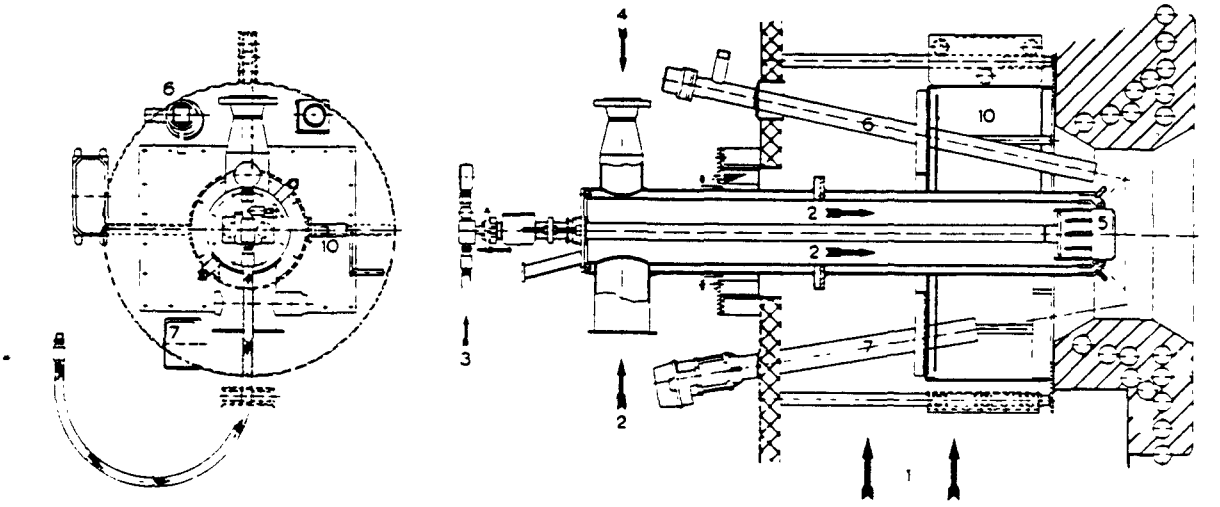
Structure of oil firing ROPM burner



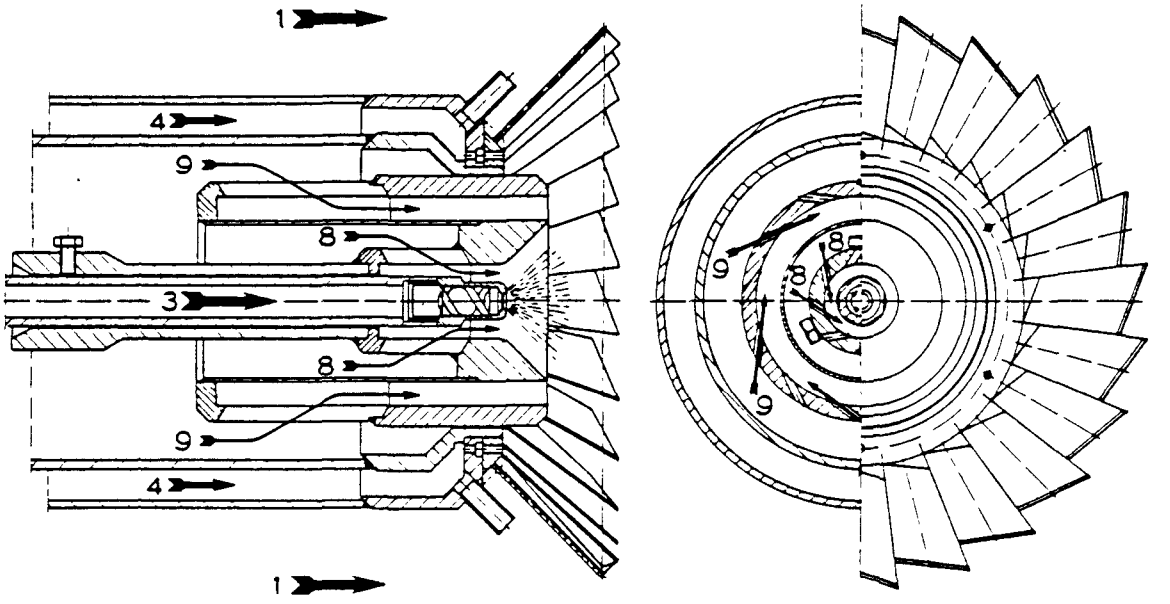
Structure of gas firing ROPM burner (Pepper, et al., 1987)

Burner assembly

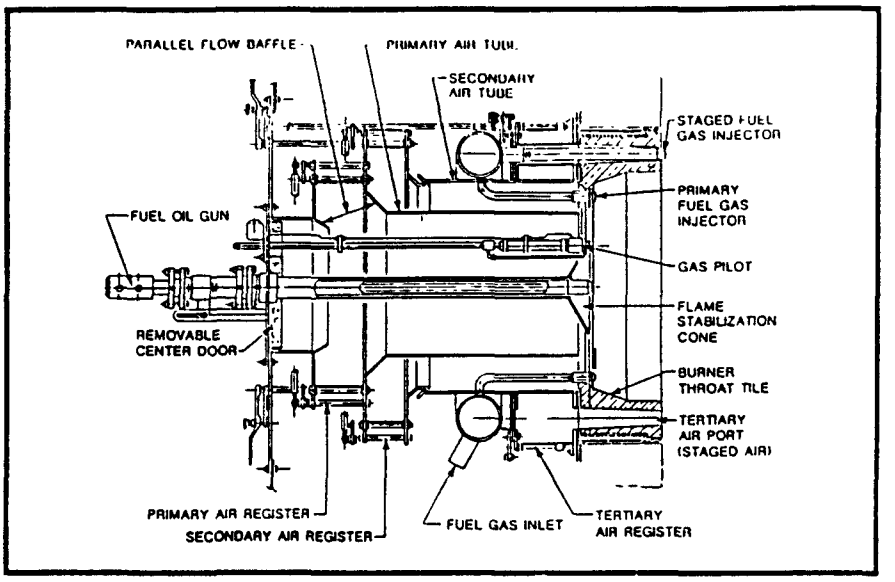
1/ Combustion air
2/ Atomizing air
3/ Oil supply
4/ Gas supply
5/ Oil burner
6/ Ignitor
7/ Flame detector
8/ First stage atomizing air
9/ Second stage atomizing air
10/ Cylindrical air damper with drive



Oil and gas burner

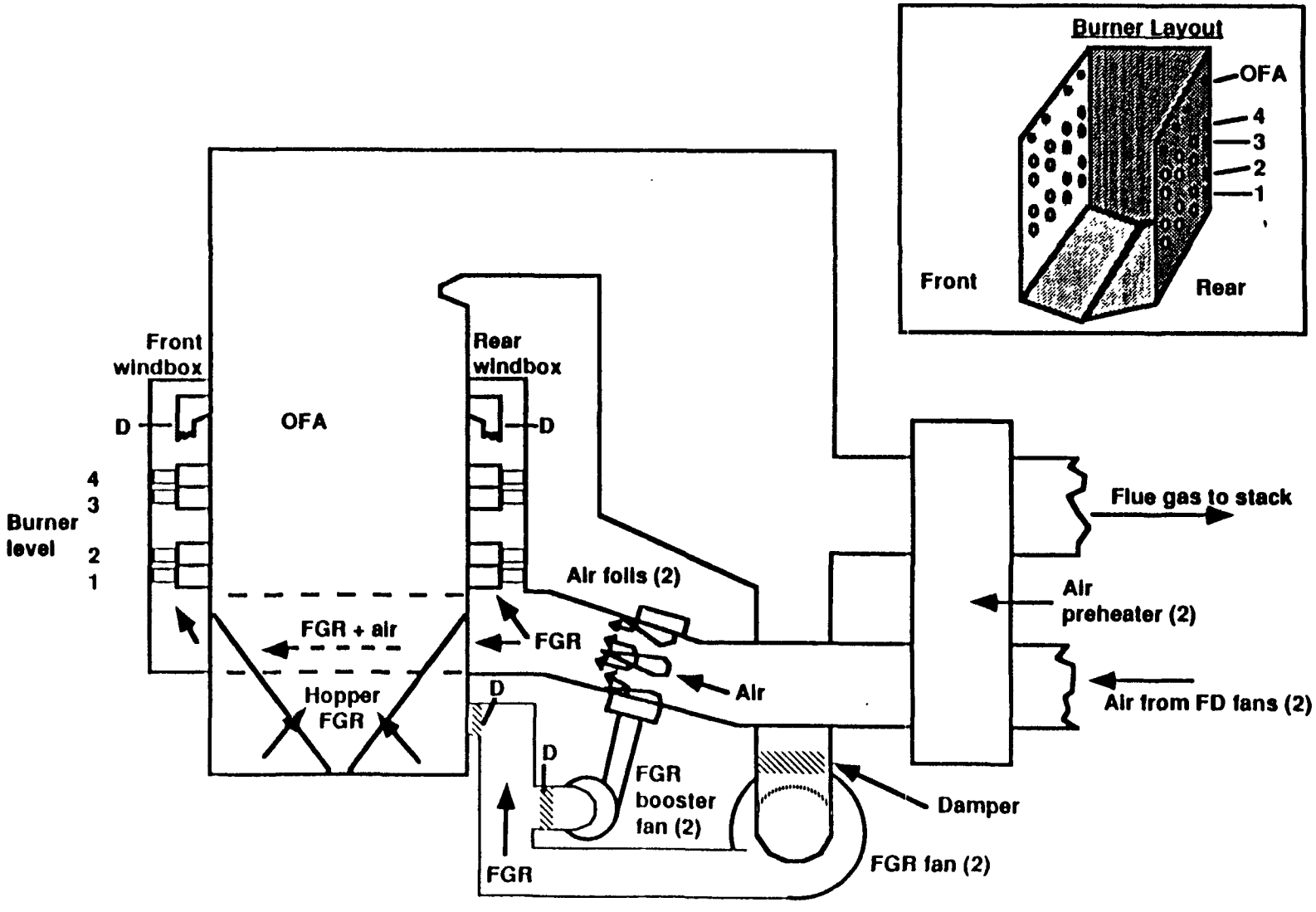


Rodenhuis and Verloop TTL/MG Burner and Atomizing Bullet Assembly (Afonso, 1991)



John Zink staged fuel/staged air $LoNO_x$ AVC boiler burner (Gerdes, 1989)

C.5 FLUE GAS RECIRCULATION AND OVERFIRE AIR (NO_x PORTS) SYSTEMS



Alamitos—Unit 6 overfire air air/FGR configuration (Bayard de Volo, 1991)

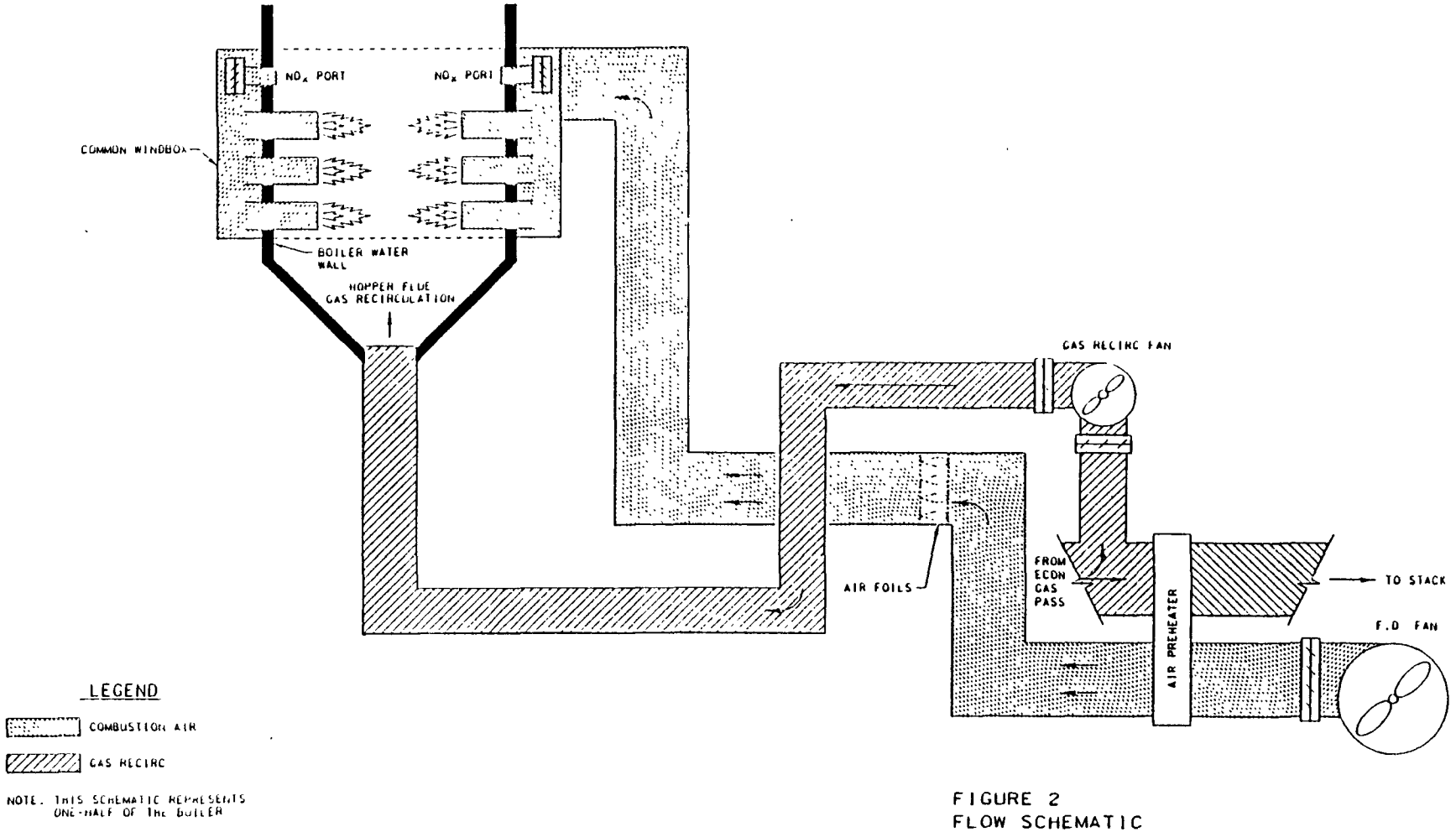


FIGURE 2
FLOW SCHEMATIC
COMBUSTION AIR & FLUE GAS DUCTS
HAYNES GENERATING STATION UNIT 3

Overfire air and hopper FGR combination (Carnevale, 1989)

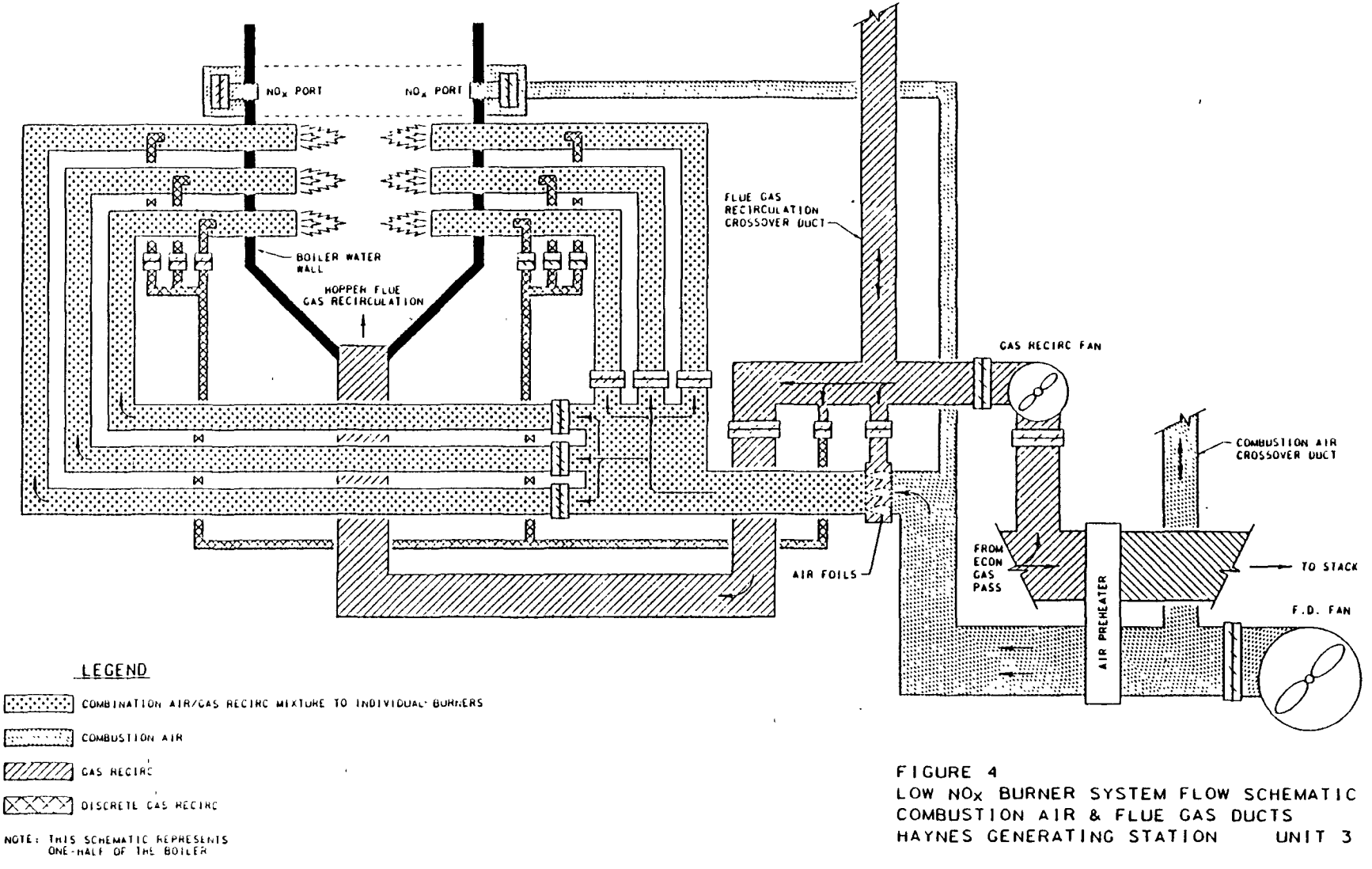
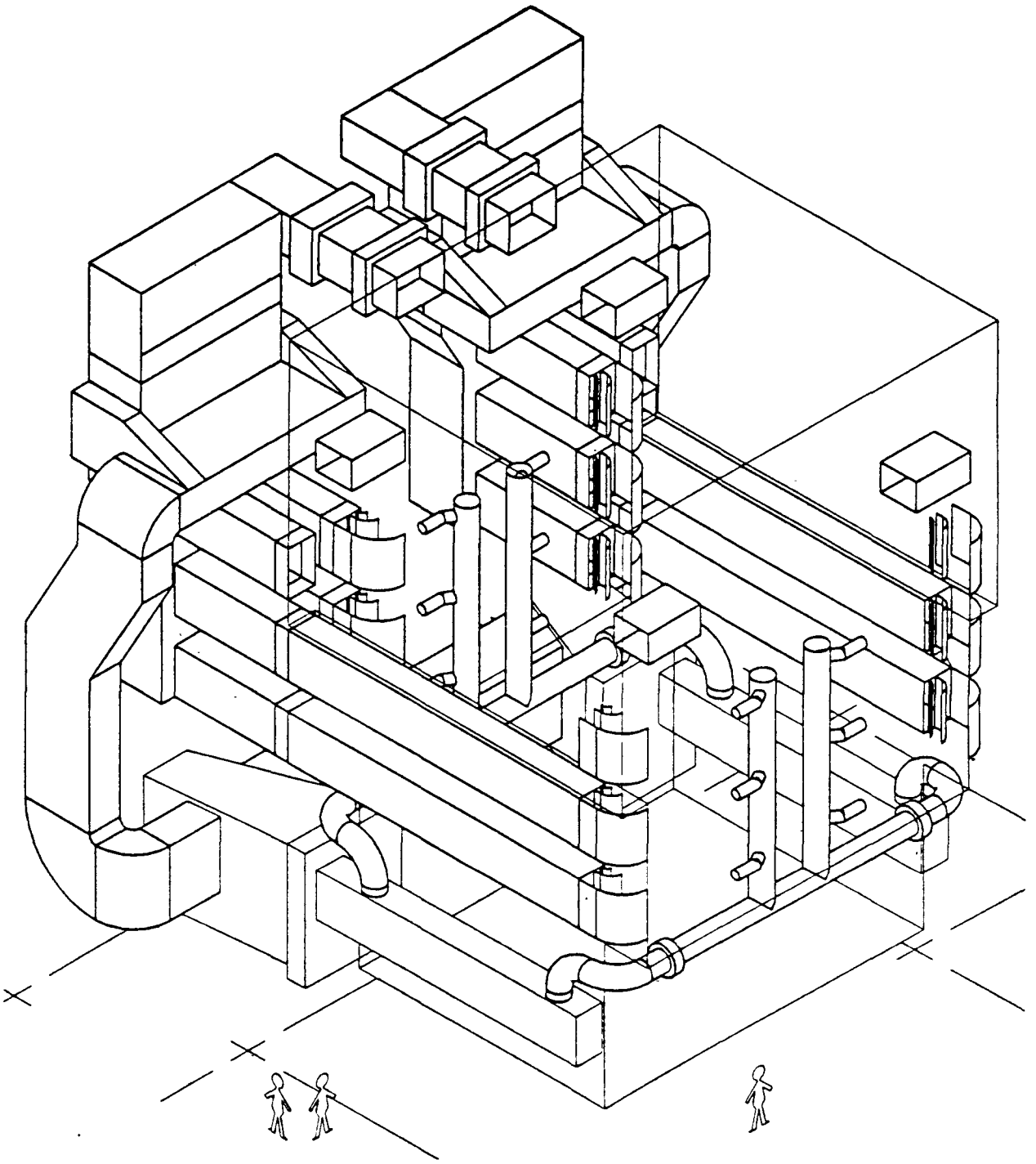


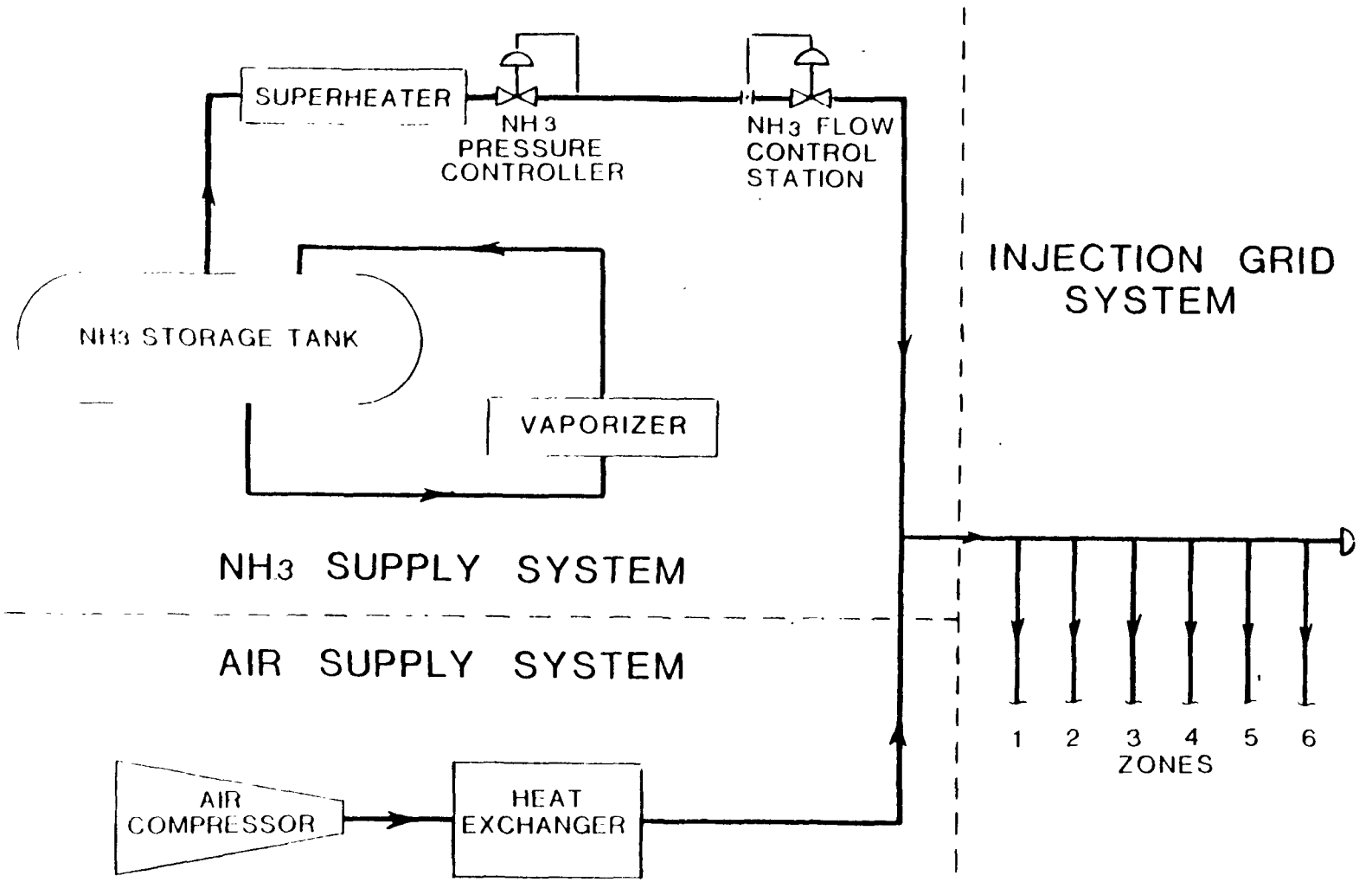
FIGURE 4
LOW NO_X BURNER SYSTEM FLOW SCHEMATIC
COMBUSTION AIR & FLUE GAS DUCTS
HAYNES GENERATING STATION UNIT 3

Schematic of OFA, LNB, and FGR (hopper and burners) for LADWP Unit 3 (Carnevale, 1989)

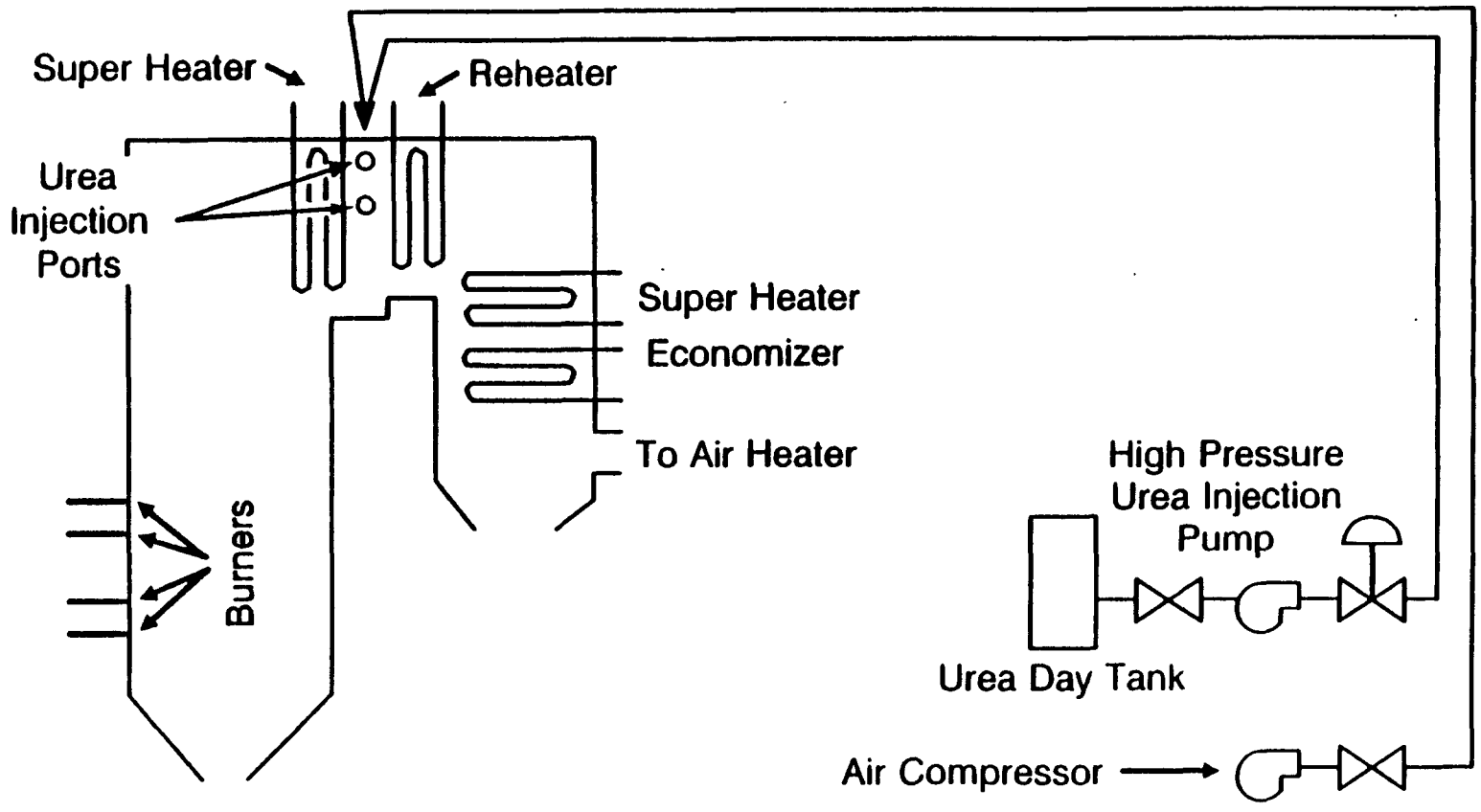


LNB + FGR + OFA ductwork on LADWP Haynes Unit 3 (Carnevale, 1989)

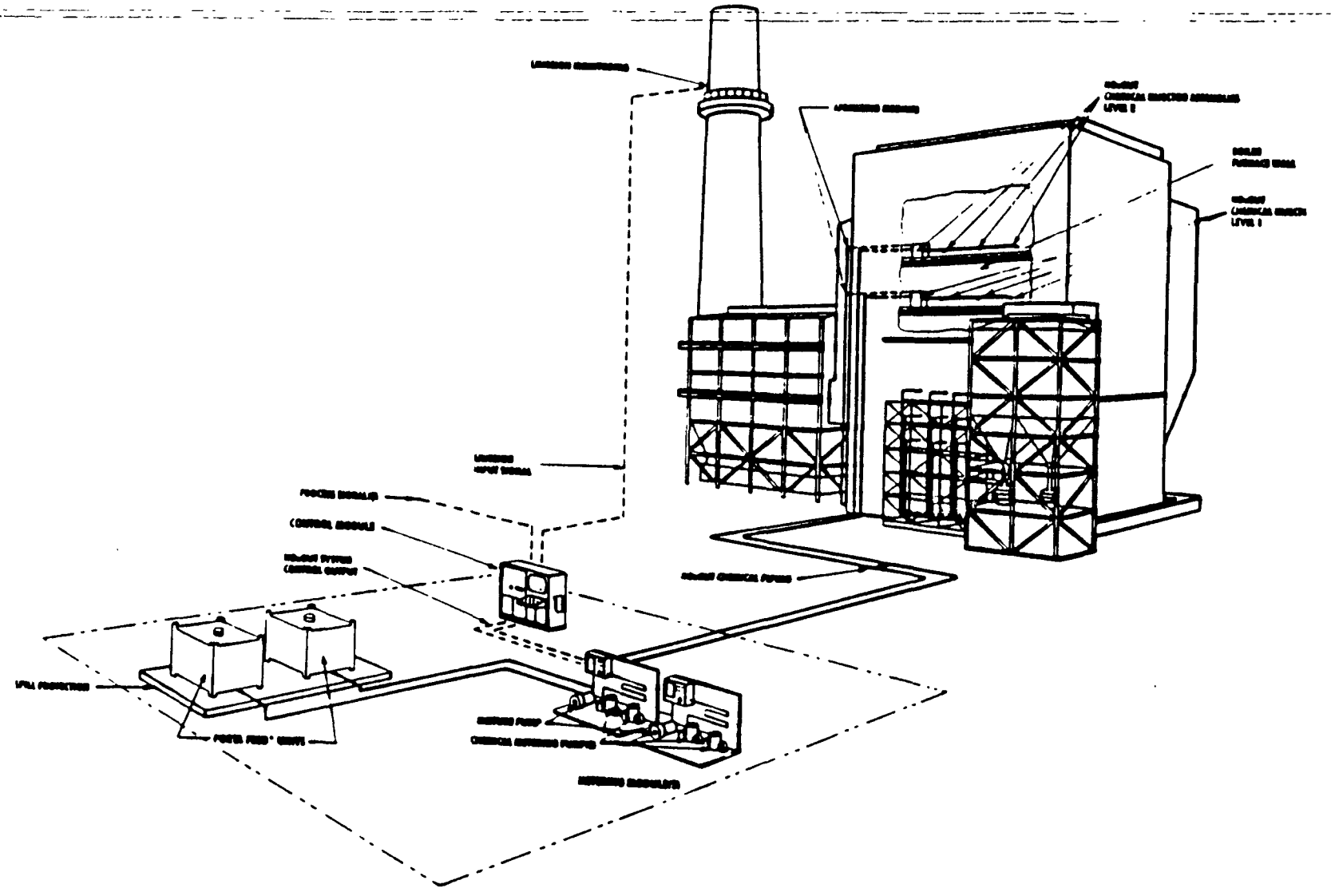
C.6 FLUE GAS TREATMENT CONTROLS



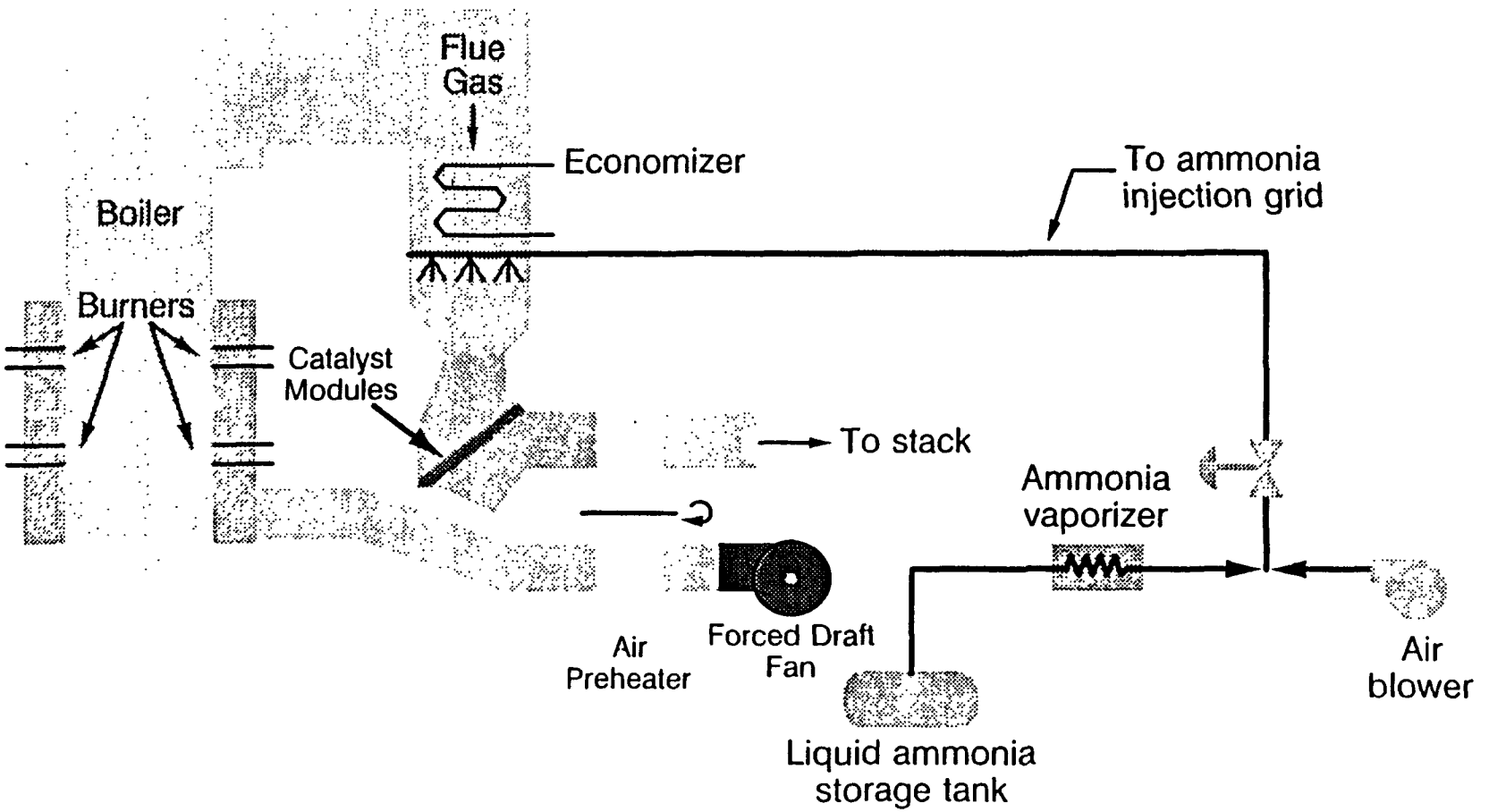
Thermal DeNO$_x$ system—process flow diagram (Dziegiel, 1983)



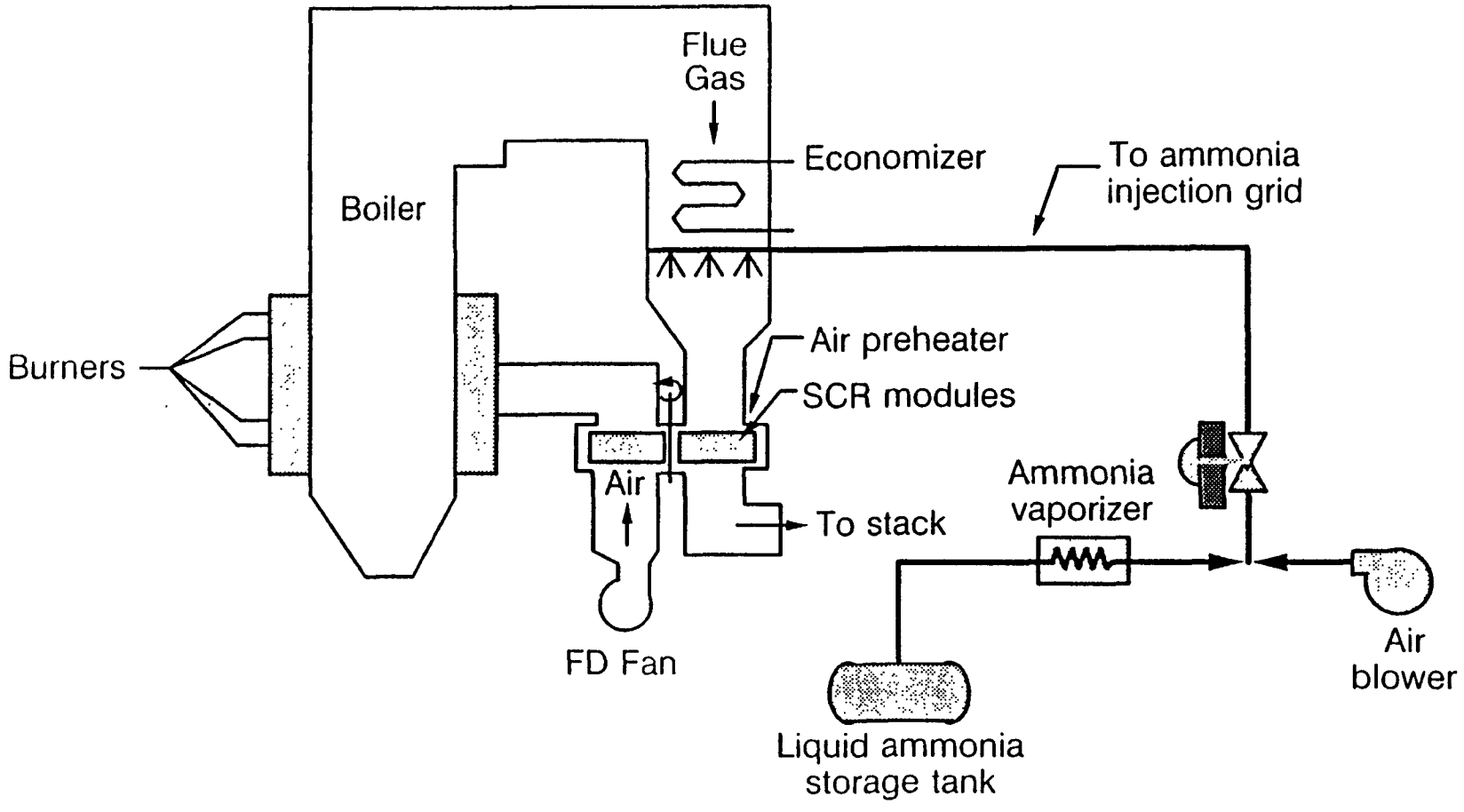
High energy urea injection demonstration project (Johnston, L., 1991)



Schematic of NOxOUT® Installation



Economizer SCR typical installation (Johnston, L., 1991)



SCR/Air preheater typical installation (Johnston, L., 1991)

AIR HEATER
- Ammonium Bisulfate Fouling
- Higher Exit Gas Temp.
- Higher Leakage
- Higher ΔP
- Higher Steam Sootblow Rate
- Higher Water Wash Rate
- Higher Steam pressure & Superheat
- Additional Dampers For On-Line Wash

BOILER
- NPHR Increase
- Temp. Bypass
- Reduced KW

FD FAN
- Higher Mass Flow
- Provide Dilution Air
- Higher Hp Consumption

AMMONIA STORAGE
- Operator Training & safety

WATER TREATMENT
- Treat AH Wash For Nitrogen

ESP
- Higher Inlet Gas Volume
- Higher Gas Temp.
- SO_3 NH_3 Conditioning
- Higher ΔP
- Resistivity Affected

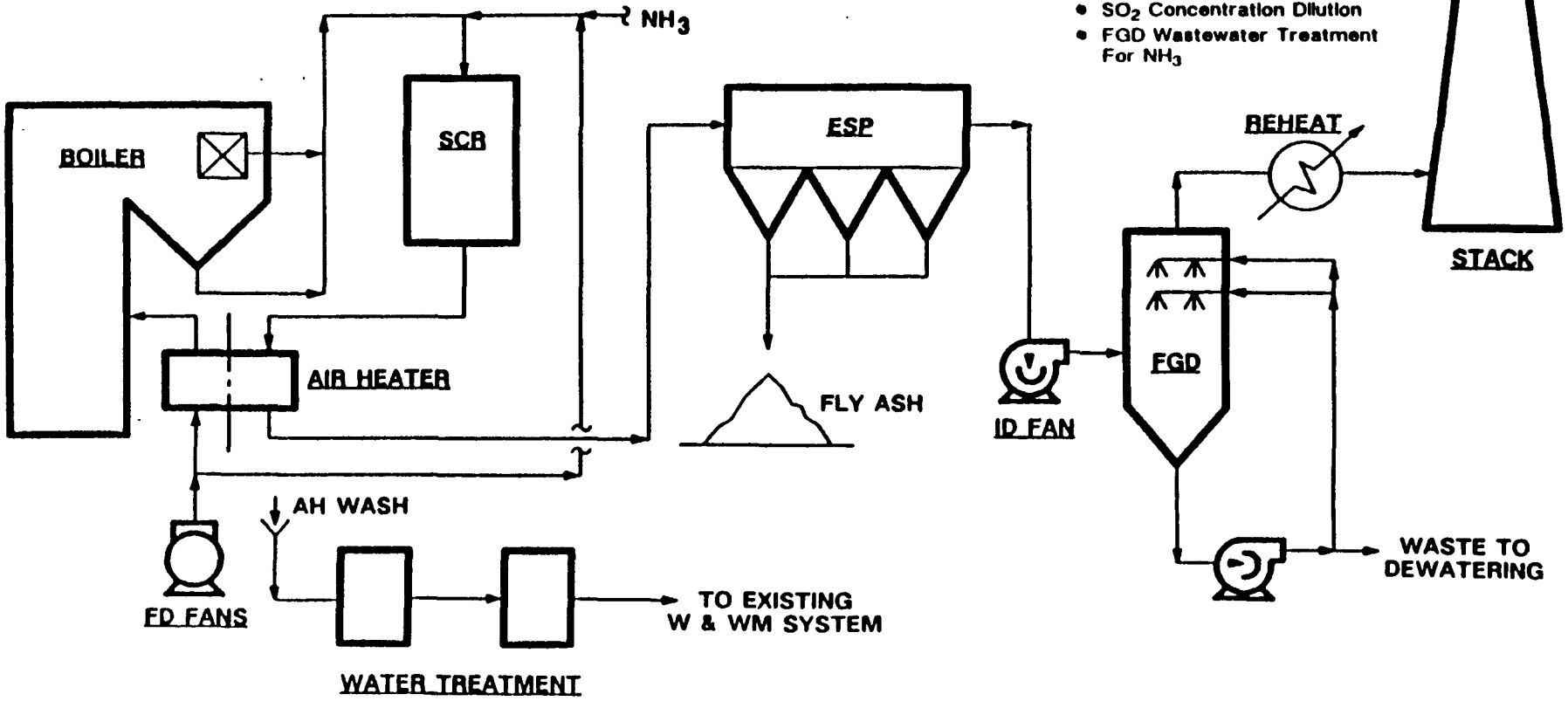
FLY ASH
- Marketability Impact
- Odor Problems
- Additional Equipment For SCR

ID FAN
- Higher Mass Flow
- Higher Volumetric Flow
- Higher ΔP

REHEAT
- Higher Mass Flow
- Increased Steam Usage

FGD
- Volume Increase
- Higher Inlet Temp.
- Increase in H_2O Evap.
- SO_2 Concentration Dilution
- FGD Wastewater Treatment For NH_3

STACK
- Increased Opacity
- Higher SO_3



Hot-side SCR design/operations impact (Robie, et al., 1991)

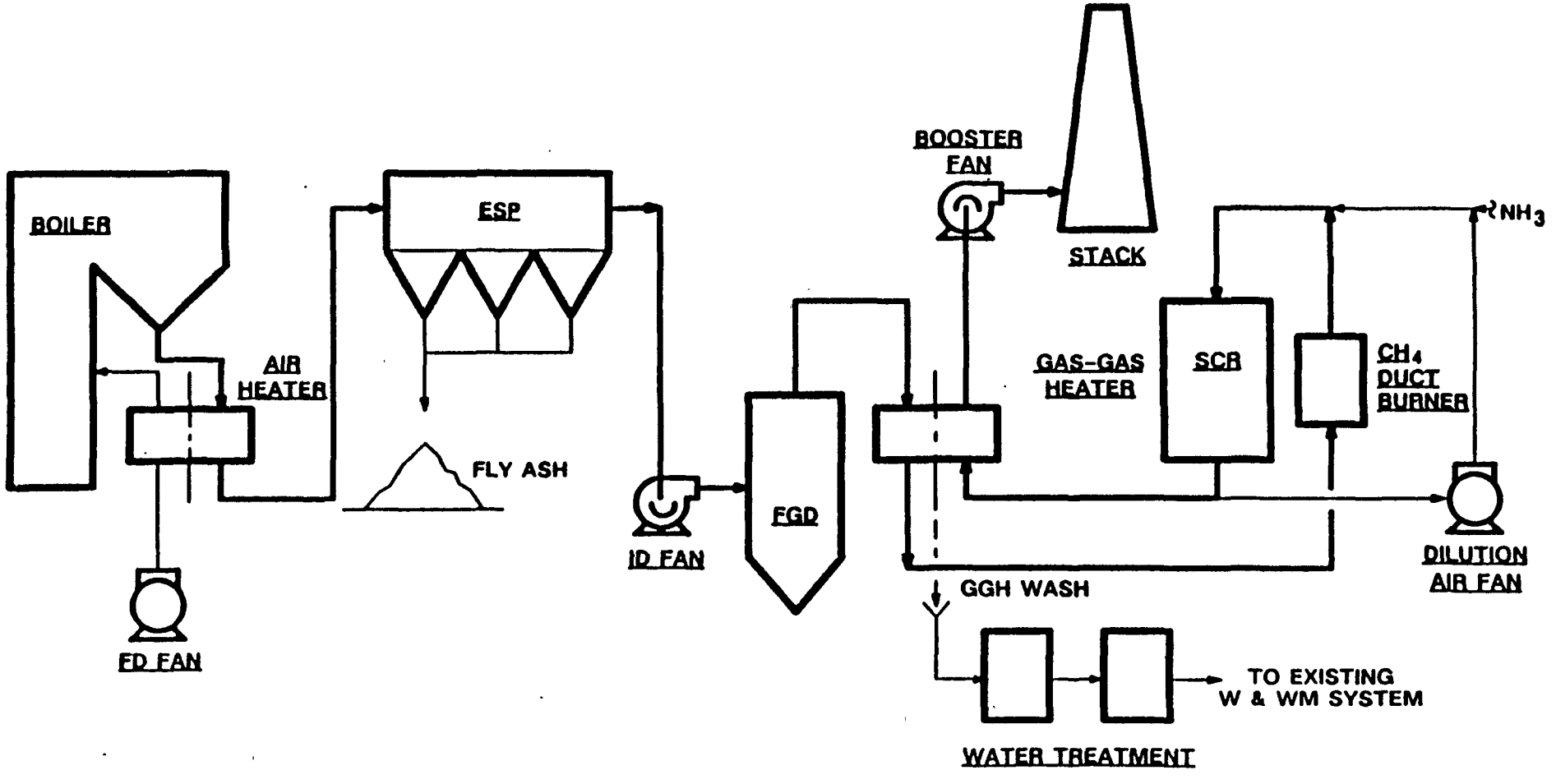
PLANT
- NPHR Increase
- Reduced Kw
- Natural Gas Supply Required
- Additional Plant Complexity

WATER TREATMENT
- Treat GGH Water Wash for Nitrogen Compounds

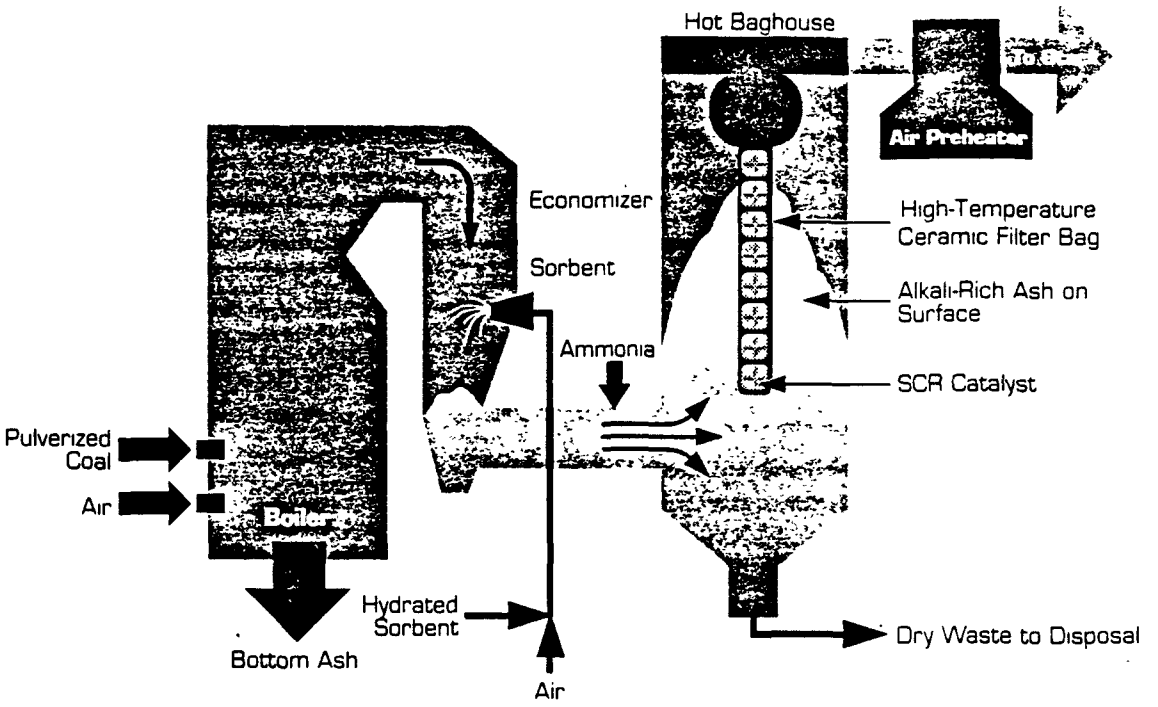
FGD
- Mist Eliminator Operation Critical

AMMONIA STORAGE
- Operator Training & Storage

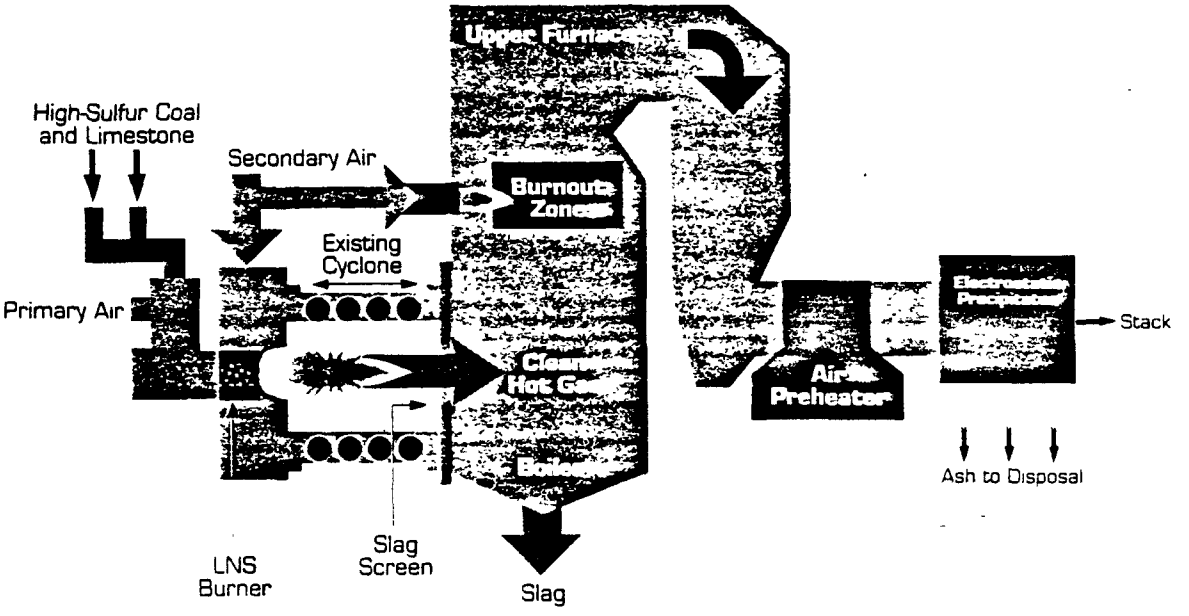
STACK
- Higher SO_3
- Increased Temperature
- Increased Opacity
- Increased Volume



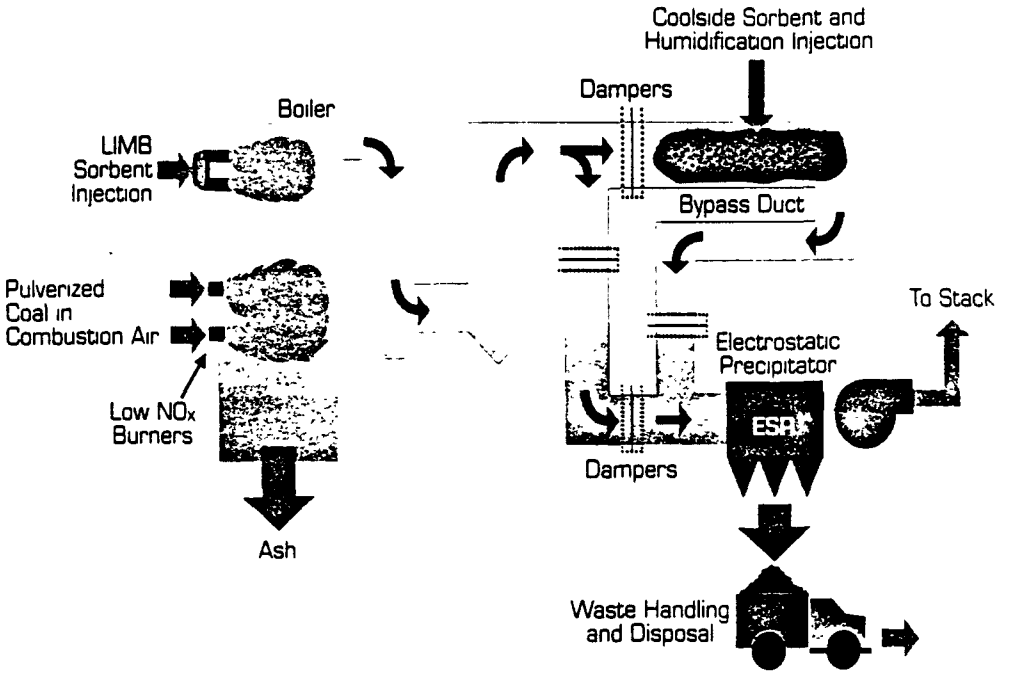
Post-FGD SCR design/operations impact (Robie, et al., 1991)



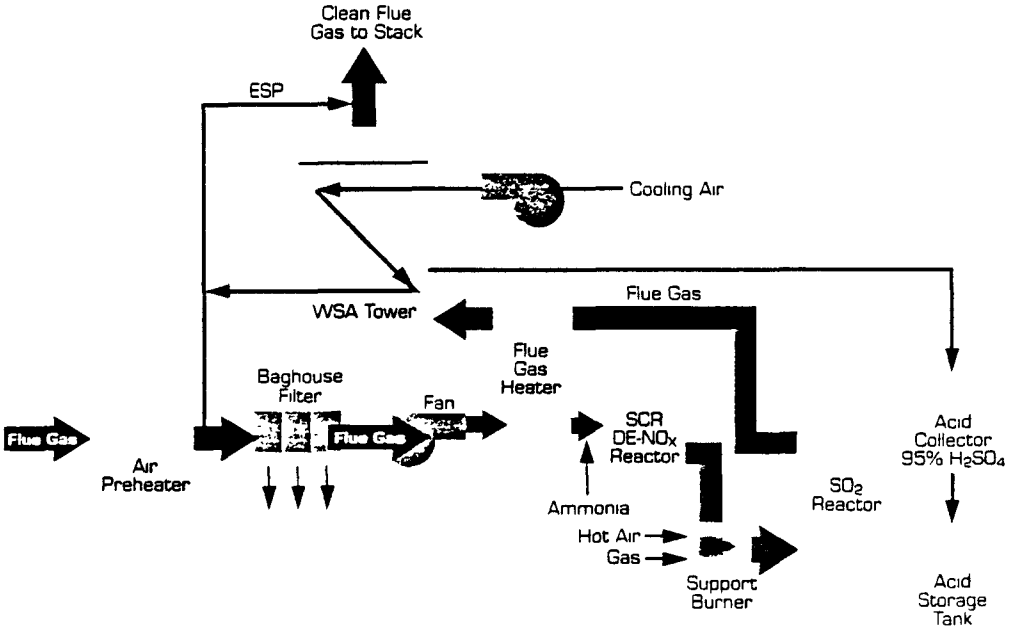
SO_x-NO_x-RO_x box flue gas cleanup



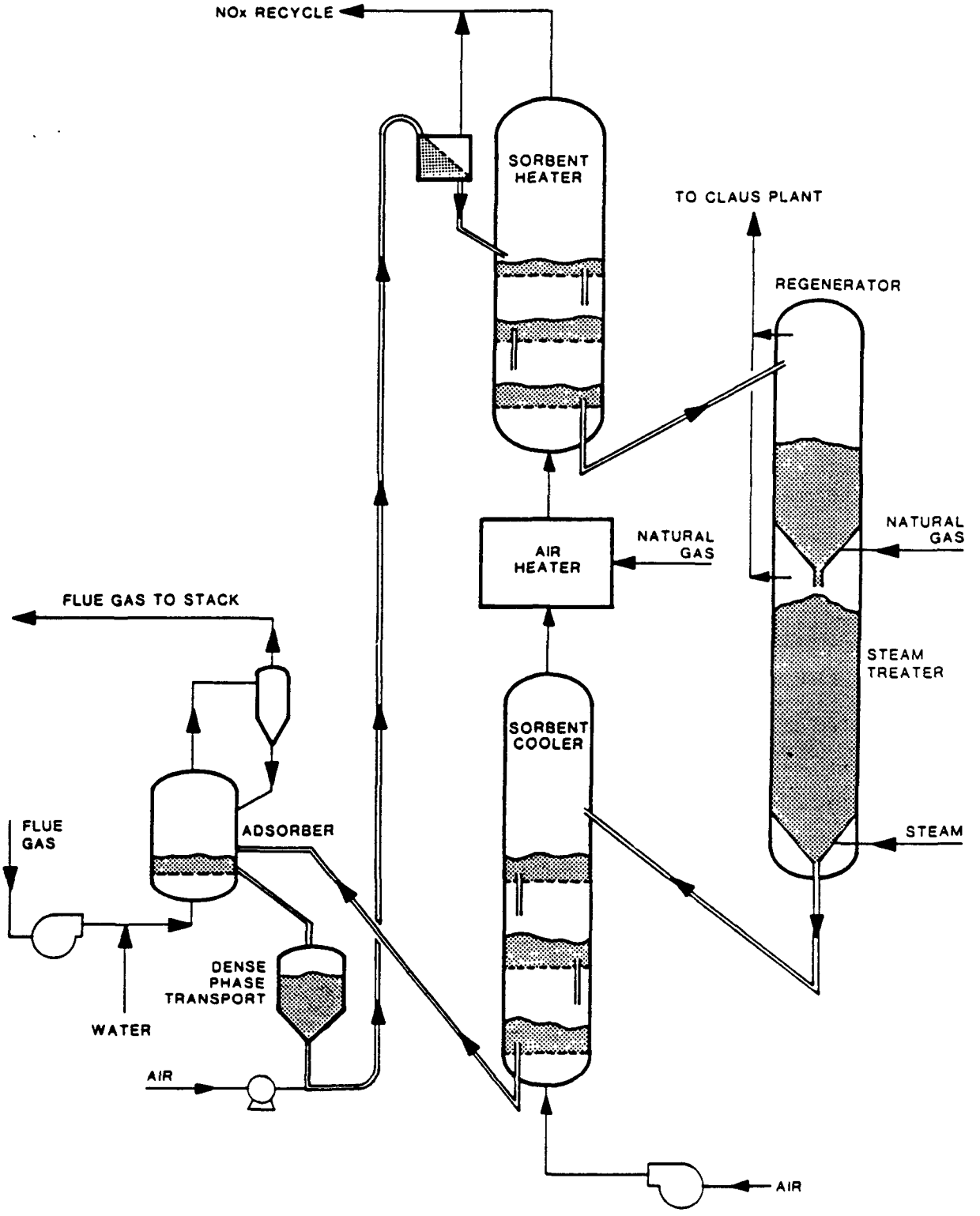
TransAlta LNS burner for cyclone-fired boilers



LIMB and coolside process diagram



WSA-SNO$_x$ flue gas cleanup



NO_xSO process flow diagram. Source: Neal, 1991

APPENDIX D

SUMMARY OF REPORTED NO_x CONTROL PERFORMANCE

This Appendix lists references and assumptions that were used to estimate NO_x control efficiencies for applicable control technologies evaluated in this study. Baseline NO_x levels for the NESCAUM boiler population are presented in Table 3-4 in the main body of the report. Percent NO_x reductions shown in bold reflect estimates of NO_x reduction potential for the NESCAUM boilers. These estimates are based on reported efficiency of NO_x controls or controlled NO_x levels achieved on other utility boilers of the same firing type and that use the same type of fuel (coal and gas/oil), taking into consideration control levels achieved and what NO_x reduction efficiency these control levels correspond to when applied to baseline levels in NESCAUM. These reduction efficiencies and controlled NO_x limits are also presented in Tables 4-1, 4-2, 4-3, and 4-6. NO_x reduction efficiencies are reported in ranges to reflect the variability of reported control performances. Generally, higher percentages of NO_x reductions apply to higher baseline NO_x levels. For example, pre-NSPS wall PC-fired boilers in the NESCAUM region are currently emitting NO_x in the range of 0.42 to 1.77 lb/MMBtu (0.95 weighted average). The control efficiency of low-NO_x burners without separate overfire air is estimated in the range of 35 to 55 percent, reflecting performances reported in the literature. Therefore, the controlled limits are estimated to vary between approximately 0.43 (0.95 x 0.45) to 0.62 (0.95 x 0.65) lb/MMBtu. This range is rounded to 0.45 to 0.60 lb/MMBtu since controlled emission limits in this study are generally rounded up in increments of 0.05 lb/MMBtu.

TANGENTIAL, DRY-BOTTOM, PC-FIRED BOILERS

Average Baseline NO_x Emission Levels (see Table 3-4)

0.45 to 0.80 lb/MMBtu—pre NSPS (range)
0.65 lb/MMBtu—pre-NSPS (average)

Reported NO_x Control Efficiencies

OFA—15- to 30-Percent NO_x Reduction

Based on efficiency range of 15 to 30 percent provided by EPRI (Miller, 1985; Thompson, 1986). Effect of OFA for the 420 MWe Utah Power & Light Hunter Unit 2 was to reduce NO_x from 460 to 360 ppm on short-term tests, about 20-percent reduction (Kokkinos, 1985) at 80-percent load.

LNB (LNCFS Burners With CCOFA)—25- to 35-Percent NO_x Reduction

Ranges in NO_x reductions are based on results from Utah Power & Light Hunter Unit 2 retrofit of LNCFS with close coupled OFA resulting in NO_x reduction from baseline levels of 460 and 360 (without and with OFA) to 240 and 260 ppm, corresponding to a control efficiency range of 33 to 48 percent (short term). Long-term tests over a 50- to 85-percent load range showed 33-percent reduction to 0.41 lb/MMBtu (Kokkinos, 1985) ABB-CE projects LNCFS Level I performance in the 25- to 32-percent range (Grusha, 1991).

SOFA+LNB (PM and LNCFS Level Levels II and III)—30- to 50-Percent NO_x Reduction

Thirty-day mean reported at 34- to 35-percent reduction to 0.45 lb/MMBtu on Plant Lansing Smith 200-MWe Unit 2 with LNCFS Level II and Level III (Hunt 1992). Results of these tests are particularly applicable because the coal is eastern bituminous, which is more representative of the NESCAUM region. Additional tests include the following. LNCFS Level III retrofit at Labadie 600-MWe Unit 2 which showed short-term performance in the 30- to 50-percent range, to a range of 0.5 to 0.69-lb/MMBtu (highly controlled levels at low loads) burning midwestern bituminous coal (Smith, 1992). Short-term tests on ENEL's 160-MWe Fusina burning U.S. bituminous coal showed 50-percent reduction with CCTFS and 30-percent SOFA from 510 to 240 ppm (ABB, 1991). NO_x reductions of 48 and 52 percent to 200 ppm levels with LNCFS Level II reported on short-term tests on Public Service of Colorado 160-MWe Valmont Unit 5 and 350-MWe Cherokee Unit 4 (Hunt, 1991; Hunt, 1992). CCTFS reduction range reported ABB in the range of 41 to 50 percent (Grusha, 1991).

Short-term tests on Kansas Power & Light 400-MWe Lawrence Unit 5 PM burner retrofit with 25-percent SOFA reporting NO_x controlled levels of 125 to 150 ppm from baseline levels of 310 to 400 ppm over load range of 40 to 80 percent (Thompson, 1989; Grusha, 1991) corresponding to reductions of about 60 percent. Results of these tests are least applicable to NESCAUM boilers because the PM technology is not likely to be used in the U.S. and because these results were obtained with high volatile coals.

Reburning—40- to 60-Percent Reduction

Based on NO_x reduction efficiency short-term full-load test results showing NO reduction from baseline of 400 ppm (0.53 lb/MMBtu) to the range of 125 to 225 ppm (0.17 to 0.30 lb/MMBtu), corresponding to a reduction of 44 to 69 percent for the 71-MWe Hennepin Station Unit 1 reburn demonstration burning high sulfur bituminous coal (Bartok, 1991); long-term tests on the same boiler showed a performance of 60-percent NO_x reduction to 0.28 lb/MMBtu (May and Kruger, 1992) and a minimum NO_x reduction of 40 percent for the technology reported by GRI (1991). Therefore, the minimum NO_x reduction efficiency is taken to be 40 percent, whereas the best reduction is taken to be 60 percent based on the long-term tests at Hennepin.

WALL AND OPPOSED, DRY-BOTTOM, PC-FIRED BOILERS

Average Baseline NO_x Emission Levels (see Table 3-4)

0.42 to 1.77 lb/MMBtu pre-NSPS range
0.95 lb/MMBtu (average)

Reported NO_x Control Efficiencies

OFA—15- to 25-Percent NO_x Reduction

Long-term tests on Georgia Power Hammond Unit 4 burning eastern bituminous coal retrofitted with 20-percent AOFA ports showed NO_x reduction from about 900 to 720 ppm (1.12 to 0.96 lb/MMBtu), 18-percent average reduction; 24-percent reduction at full load (Sorge, 1992) and 670 ppm to 550 ppm (0.89 to 0.73 lb/MMBtu), 19-percent at low load (Wilson, 1991).

Allegheny Power Pleasant 650-MWe Unit 2 post-NSPS unit equipped with OFA. Long-term tests show NO_x reduction from 0.95 to 0.65 lb/MMBtu at full load (33-percent reduction) (Vatsky, 1989). The low range in performance (15-percent reduction efficiency) was also reported by EPRI (Miller, 1985).

LNB—35- to 55-Percent NO_x Reduction

Results at Hammond 500-MWe Unit 4 show a 30-day, 48-percent NO_x reduction average to 0.64 lb/MMBtu; 53 percent based on 94-day average from 1.12 baseline to 0.53 lb/MMBtu (Sorge, 1992). Short-term tests on Harrison 500-MWe Unit 4 also showed 55-percent reduction to a level of 0.5 to 0.6 lb/MMBtu (Vatsky, 1989). TVA Johnsonville results report 53-percent reduction, short-term, to 0.45 lb/MMBtu (McAusker, 1992). B&W LNB retrofits report short-term NO_x reductions of 46 percent at Gaston 250 MWe Unit 2 (Hardman, 1992); 43 percent at Edgewater 100 MWe Unit 4 (LaRue, 1989); and 55 percent at Stuart 605 MWe Unit 4 (Laursen, 1992). Controlled levels for these B&W retrofits range between 0.40 and 0.53 lb/MMBtu. Lowest performance reported at San Juan with 34-percent NO_x reduction (Vatsky, 1995) and foreign LNB retrofits (VanDerKooji, 1991).

Additional results include NO_x reduction for Pleasant Unit 2 opposed firing retrofit with CF/SF were 55 to 60 percent from pre-NSPS levels to 0.4 lb/MMBtu and 43 percent from post NSPS of 0.7 lb/MMBtu. These levels achieved without OFA at full load (Vatskey, 1989). Four Corners Units 4 and 5 subbituminous opposed firing retrofit of CF/SF LNB without OFA reduced NO_x from pre-NSPS level of 1.28 lb/MMBtu (cell-burners) to a range of 0.48 to 0.52 lb/MMBtu corresponding to about 60-percent reduction (Vatsky, 1989). Retrofit of other boilers with CF/SF LNBs show controlled levels in the range of 0.35 to 0.50 lb/MMBtu (Vatksy, 1989) corresponding to reductions of 40 to 55 percent from NESCAUM boilers baseline levels.

LNB + OFA—40- to 60-Percent NO_x Reduction

Only two domestic pre-NSPS boilers have been tested with LNB + OFA. Of these, only one, the Hammond 500-MWe Unit 4, is burning eastern bituminous coal. Short-term test results show a 60-percent NO_x reduction to levels of 0.54 lb/MMBtu (Sorge, 1992). The second retrofit, Allegheny Power Pleasant 650-MWe Unit 2 retrofitted with CF/SF and

OFA, reduced NO_x from 0.90 to 0.95 lb/MMBtu, uncontrolled without OFA, to 0.33 lb/MMBtu (60- to 65-percent NO_x reduction) on short-term tests at full-load burning a more volatile coal (Vatksy, 1989).

Additional tests concluded San Juan Unit 1 of Public Service of New Mexico with a short-term performance of 65 percent (Vatsky, 1989) and two foreign installations with reported long-term performed in the range of 60 to 64 percent (Vatsky, 1991 and VanDerKooji, 1991).

Reburning—45- to 60-Percent NO_x Reduction

No test data available yet on the only one domestic wall-fired demo at Public Service of Colorado 158-MWe, Cherokee Unit 3. Assumed NO_x reduction efficiency based on tangential 71-MWe Hennepin Unit 1 (see tangential data). However, the low end of NO_x reduction performance is increased slightly, from 40 to 45 percent, because higher NO_x reduction efficiency is anticipated with the higher baseline level of wall-fired units.

CYCLONE, COAL-FIRED BOILERS

Average Baseline NO_x Emission Levels (see Table 3-4)

1.28 lb/MMBtu (21 to 30 years of service)

Reported NO_x Control Efficiencies

Reburning—45- to 60-Percent NO_x Reduction

Ohio Edison Niles Station Unit 1, 108 MWe, burning eastern bituminous coal, retrofitted with 18-percent gas reburn with 10-percent FGR. Short-term tests at full load show reduction from 700 ppm to 300 ppm (0.93 to 0.40 lb/MMBtu), 57-percent reduction. At 80 percent of full load, NO_x reduced from 620 to the range of 250 to 300 ppm (52 to 60 percent) on short-term tests. Long-term performance at Niles was reported to range between 46 and 48 percent (Brown, 1992). With coal as the reburning fuel, NO_x reductions of 30 to 53 percent over the load range were reported at Nelson Dewey 100 MWe Unit 2 (Newell, 1992). Therefore, the lowest performance for natural gas reburn is taken to be 45 percent based on Brown's results. The best performance is taken to be 60 percent based on short-term test results.

TANGENTIAL, OIL-, AND GAS-FIRED BOILERS

Average Baseline NO_x Emission Levels (see Table 3-4)

0.34 lb/MMBtu (average post-NSPS)
0.24 lb/MMBtu (average pre-NSPS)
0.28 lb/MMBtu (average all units)

Reported NO_x Control Efficiencies

Two-Staged Combustion (BOOS or OFA)—15- to 20-Percent NO_x Reduction (Pre-NSPS)
25- to 40-Percent NO_x Reduction (Post-NSPS)

NO_x reduction estimated by Con Edison to be approximately 30 percent (Mormile, 1991), corresponding to the average of the range estimated for NESCAUM. Other estimates reported by Hunter, 1989, and Lim, 1980, for Northeast and California utilities were reported as high as 45 and 55 percent, respectively.

NO_x reduction efficiency was based on the results for wall-fired boilers (Kehro, 1991 and Bayard de Volo, 1991), which indicated controlled NO_x levels with BOOS and OFA in the range of 0.19 to 0.28 lb/MMBtu. 0.19 lb/MMBtu corresponds to reduction efficiency of less than 20 percent from current NESCAUM (pre-NSPS) baseline level of 0.24 lb/MMBtu and 20 to 40 percent from the post-NSPS level of 0.34 lb/MMBtu.

Windbox Flue Gas Recirculation—25- to 40-Percent NO_x Reduction (Pre-NSPS)
20- to 30-Percent NO_x Reduction (Post-NSPS)

Six SCE Units in the range of 320 to 330 MWe operating on oil with 20-percent FGR at full load reduced NO_x from about 350 ppm to a range of 215 to 245 ppm, 30- to 40-percent reduction (Lim, 1980). Con Edison predicts 23-percent NO_x reduction with 15-percent FGR (Mormile, 1987).

Two-Staged Combustion and Flue Gas Recirculation—30- to 50-Percent NO_x Reduction (Pre-NSPS)
30- to 40-Percent NO_x Reduction (Post-NSPS)

PG&E Pittsburgh Unit 7 equipped with FGR and TSC, with OFA ports, resulted in long-term operation with controlled NO_x levels as low as 175 ppm (about 0.20 lb/MMBtu) from a baseline of about 750 ppm, corresponding to a reduction of 77 percent (Lim, 1980). For the NESCAUM oil/gas T-fired population, the uncontrolled NO_x level of 175 ppm represents a reduction potential of about 30 percent from current baseline levels. Experience reported in Southern California with SCE boilers shows controlled NO_x levels achieved with this combination of controls in the range of 0.10 to 0.20 lb/MMBtu (Bayard de Volo, 1991) principally with natural gas fuel. This range corresponds to an NO_x reduction efficiency of 40 to 60 percent. Lower percent reductions are likely with heavier oil and with low initial NO_x levels shown by tangential units.

Low-NO_x Burners—25- to 50-Percent NO_x Reduction (Pre-NSPS)
20- to 40-Percent NO_x Reduction (Post-NSPS)

Tests performed on ENEL's Fusina 160-MWe Unit 2 coal-/oil-/gas-fired boiler. Baseline emissions on oil/gas are about 200 to 250 ppm. Short-term tests with CCFTS resulted in controlled NO_x levels in the range of 125 to 150 (0.16 to 0.19 lb/MMBtu); corresponding to a reduction of 25 to 50 percent at full load (Grusha, 1991). Performance sensitive to fuel nitrogen. Although those tests may not be considered representative of NO_x reduction performance for boilers designed for gas and oil firing, several units in NESCAUM have undergone fuel switching. Recent tests on a non-tangential boiler by New England Power (NEPCO) Company showed controlled levels in the range of 0.27 to 0.15 lb/MMBtu with LNB retrofit (Afonso, 1992). These levels correspond to a reduction of about 20 to 50 percent from average baseline levels. Estimates as high as 60-percent reduction with LNB by Con Edison are not deemed applicable to initially low levels of baseline NO_x.

OFA (BOOS) + FGR + LNB—40- to 60-Percent NO_x Reduction (Post-NSPS)
40- to 70-Percent NO_x Reduction (Pre-NSPS)

NO_x controlled levels reported to date for this combination of controls on gas-/oil-fired boilers show a range of 0.10 to 0.20 lb/MMBtu (Bisonett, 1991, Kehro, 1991; Bayard de Volo, 1991). See results reported for wall-fired units. These levels are deemed attainable with tangential units but will depend on properties of fuel burned. Therefore, control efficiencies are estimated to range between 40 and 70 percent from current control levels of T-fired boilers.

Reburning—50- to 60-Percent NO_x Reduction (Pre-NSPS)
30- to 50-Percent NO_x Reduction (Post-NSPS)

Pilot tests at ABB Boiler Simulation Facility with plans for full-scale retrofits on ENEL boilers in Italy show NO_x reduction of 50 to 60 percent on natural gas fuel with 15-percent reburn (ABB, 1991). Full-scale reductions of 60 percent achieved with fuel oil reburning fuels on one demonstration in Italy (DeMichele, 1992). Maximum NO_x reductions are estimated to be on the same order of magnitude as LNB-based controls. These estimates are highly speculative because of lack of full-scale data and experience.

WALL AND OPPOSED OIL- AND GAS-FIRED BOILERS

Average Baseline NO_x Emission Levels (see Table 3-4)

0.35 lb/MMBtu (average post-NSPS)
0.52 lb/MMBtu (average pre-NSPS)
0.45 lb/MMBtu (average all units)

Reported NO_x Control Efficiencies

Two-Staged Combustion (BOOS or OFA)—30- to 35-Percent NO_x Reduction (Pre-NSPS)
25- to 35-Percent NO_x Reduction (Post-NSPS)

BOOS on Hawaiian Electric Co. (HECO) Kahe 146-MWe Unit 6 resulted in a 38-percent reduction from baseline levels of 0.8 lb/MMBtu firing oil with approximately 0.3-percent fuel-bound nitrogen (Yee, 1989). Tests with one row of BOOS on Salem Harbor Unit 4 showed NO_x reductions equivalent to that achieved with oil/gas LNB, 43 percent (Afonso, 1992). Long-term operation under this BOOS pattern was not considered acceptable, however.

SCE Los Alamitos 460-MWe opposed gas-fired Unit 6 with uncontrolled NO_x emissions of 700 ppm. Long-term tests at full load show reduction by 79 percent, to 150 ppm (Bayard de Volo, 1991). Controlled level of 150 ppm (0.19 lb/MMBtu) corresponds to average reduction of about 50 percent from all NESCAUM boilers. However, this performance is expected only when natural gas is burned in a high heat release unit. Con Edison estimates performance at 30 to 35 percent (Mormile, 1991; Mormile 1987).

Windbox Flue Gas Recirculation—25- to 40-Percent NO_x Reduction (Pre-NSPS)
20- to 30-Percent NO_x Reduction (Post-NSPS)

PG&E Contra Costa 345-MWe oil-/gas-fired pre-NSPS boiler retrofitted with OFA and FGR reduced NO_x emissions from 330 to 420 ppm at full load to 200 to 180 ppm with controls (39- to 52-percent reduction), long-term tests (Bisonett, 1991).

Ten-percent FGR on HECO's 146-MWe Kahe Unit 6 resulted in a reduction of 48 percent to an NO_x level of about 320 ppm (0.40 lb/MMBtu) with 0.3-percent nitrogen oil (Yee, 1989). This controlled level corresponds to 25-percent reduction from pre-NSPS NESCAUM units. Con Edison predicts 23-percent reduction with 15-percent FGR (Mormile, 1987).

Two-Staged Combustion (BOOS or OFA) and Flue Gas Recirculation
—40- to 50-Percent NO_x Reduction (Pre-NSPS)
40- to 50-Percent NO_x Reduction (Post-NSPS)

Hawaiian Electric Co. Kahe 146-MWe Unit 6, oil-/gas-fired. Long-term tests with BOOS and 10-percent FGR showed controlled NO_x levels to 220 ppm (0.28 lb/MMBtu) at full load (Kehro, 1991). Controlled level of 0.28 corresponds to a reduction of 30 percent from average baseline emissions from all NESCAUM boilers.

SCE Los Alamitos 460-MWe opposed gas-fired Unit 6 with uncontrolled NO_x emissions of 700 ppm. Short-term tests at full load show reduction by 91 percent to 65 ppm (0.08 lb/MMBtu) (Bayard de Volo, 1991). From average NESCAUM boiler emissions this level of control corresponds to a reduction of 80 percent.

SCE Ormond Beach 820-MWe Unit 2 with FGR and BOOS reduced emissions from 1,200 ppm uncontrolled to 120 to 150 ppm (0.15 to 0.19 lb/MMBtu) over the 400- to 700-MWe load range during 1-month duration tests (Bayard de Volo, 1991). This level of control translates to an average NO_x reduction of 55 to 65 percent from NESCAUM baseline levels. PG&E estimates NO_x reductions of 43 percent for 345-MWe Contra Costa Unit 6 with oil and 50 percent with gas (Bisonett, 1991).

Low-NO_x Burners (LNB)—40- to 50-Percent NO_x Reduction (Pre-NSPS)
30- to 40-Percent NO_x Reduction (Post-NSPS)

Retrofit of PG-DRB burners at HECO's Kahe 146-MWe Unit 6 resulted in an NO_x reduction from about 600 ppm (0.8 lb/MMBtu) to 400 ppm (0.53 lb/MMBtu), corresponding to a 33-percent reduction (Yee, 1989).

Recent tests at Salem Harbor 435-MWe Unit 4 showed short-term NO_x reduction of 43 percent (Afonso, 1992). B&W tests on pilot-scale facility using XCL gas/oil LNB show 75 ppm (0.1 lb/MMBtu for gas) without FGR from 160 ppm uncontrolled (about 50 percent reduction). No. 6 oil results from uncontrolled 210 to 120 ppm (0.27 to 0.15 lb/MMBtu) with no FGR (LaRue, 1989). This level of control translates to a reduction efficiency of 33 to 63 percent, the average NESCAUM baseline level. Con Edison estimates 60-percent reduction for LNB (Mormile, 1987). This level is considered optimistic.

BOOS + FGR—40- to 50-Percent NO_x Reduction (Pre-NSPS)
40- to 50-Percent NO_x Reduction (Post-NSPS)

Con Edison reports control efficiency in the range of 45 to 50 percent (Mormile). Control efficiency reported in the range of 19 to 76 percent, with an average for five utility boilers at 55 percent (Lim, 1980). For NESCAUM, the efficiency is estimated to be no greater than that achievable with LNB retrofit.

OFA (BOOS) + FGR + LNB—60- to 80-Percent NO_x Reduction (Pre-NSPS)
45- to 70-Percent NO_x Reduction (Post-NSPS)

PG&E Contra Costa 345-MWe oil-/gas-fired pre-NSPS boiler showed short-term NO_x reduction from 330 to 420 ppm to 70 to 150 ppm (65- to 78-percent reduction) at full load (Bisonett, 1991).

Hawaiian Electric Co. Kahe 146-MWe Unit 6 oil-/gas-fired. Retrofit of PG-DRB, OFA, and FGR resulted in NO_x controlled levels of 0.19 lb/MMBtu at full load during short-term tests (Kehro, 1991); corresponds to about 60-percent reduction from average baseline level of 0.45 lb/MMBtu for all wall-fired boilers in NESCAUM.

SCE Los Alamitos 460-MWe opposed gas-fired Unit 6 with uncontrolled NO_x emissions of 700 ppm. Short-term tests at full load show reduction of 49 ppm (93-percent reduction over the load range of 100 to 500 MWe) (Bayard de Volo, 1991); corresponds to 80-percent reduction using average NESCAUM baseline.

These retrofits represent a controlled NO_x range of 0.10 to 0.20 lb/MMBtu, depending on fuel type. This control range corresponds to control efficiency of about 60 to 80 percent from pre-NSPS baseline of 0.52 lb/MMBtu, and 45 to 70 percent from post-NSPS baseline of 0.35 lb/MMBtu.

SCE Ormond Beach 820-MWe Unit 2 burning gas/oil. Retrofitted with Todd Dynaswirl burners and FGR + BOOS reduced NO_x from 1,200 ppm uncontrolled to 90 to 150 ppm over load range from 400 to 700 MWe and 1-month duration tests (Bayard de Volo, 1991); corresponds to 50- to 70-percent reduction from average NESCAUM baseline levels.

SCE Los Alamitos 460-MWe opposed gas-fired Unit 6 with uncontrolled NO_x emissions of 700 ppm. Short-term tests at full load show reduction by 75 percent to 174 ppm (Bayard de Volo, 1991).

Reburning—50- to 60-Percent NO_x Reduction (Pre-NSPS)
30- to 50-Percent NO_x Reduction (Post-NSPS)

Pilot-tests at ABB Boiler Simulation Facility with plans for full-scale retrofits on ENEL boilers in Italy show NO_x reduction of 50 to 60 percent on natural gas fuel with 15-percent reburn (ABB, 1991). PG&E estimates 30- to 73-percent NO_x reduction (average 58 percent) for 5 boilers ranging in size from 330 to 700 MWe (Bisonett, 1991). No test data available on full-scale utility boilers. Maximum NO_x reductions are estimated to be on the same order of magnitude as LNB-based controls. These estimates are highly speculative because full-scale data and experience are lacking.

COAL-FIRED DRY-BOTTOM BOILERS

Average Baseline NO_x Emission Levels (All Boiler Designs)

0.75 lb/MMBtu (pre-NSPS)

Combustion Controlled NO_x Levels (All Boiler Designs)

0.25 to 0.40 (0.33) lb/MMBtu (all boilers)

Reported NO_x Control Efficiency

Selective Noncatalytic Reduction (SNCR)—25- to 40-Percent NO_x Reduction from Controlled Levels
30- to 50-Percent NO_x Reduction from Uncontrolled Levels

Reduction based on short-term results on these installations:

Wisconsin Electric Power Co. Valley Power Plant Unit 4 (650,000 lb/hr) showed short-term NO_x reduction of 60 to 70 percent from uncontrolled levels of about 1.3 lb/MMBtu at full load with NSR in the range of 1.0 to 1.5 using the NOXOUT process. These high performance levels are not considered feasible with lower NSR, lower baseline levels, and larger utility boilers. NO_x was reduced by 50 percent at partial load from level of 0.66 lb/MMBtu (Nalco, 1992). Public Service of Colorado, Arapahoe 100-MWe Unit 4 recent retrofit showed only 25- to 40-percent reduction (Hunt, 1992).

German RWE 150-MWe and 75-MWe brown coal boilers where initial combustion-controlled NO_x was 150 ppm and was reduced to 100 ppm (33 percent reduction) with boiler load down to 60 percent of capacity. Reported capability set in the 30- to 50-percent NO_x reduction range (Hofmann, 1989).

Kerr-McGee Argus Unit No. 26 (710,000 lb/hr) industrial size boiler. Initial NO_x emissions reduced to 225 ppm with further NO_x reduction to 165 ppm with urea injection (NOXOUT) for a reduction efficiency of SNCR of 27 percent (Comparato, 1989).

Selective Catalytic Reduction (SCR)—80-Percent NO_x Reduction from Uncontrolled Levels
70-Percent NO_x Reduction from Controlled Levels

NO_x reduction based on reported SCR performance for installations worldwide that shows reductions in the range of 70 to 80 percent (IEA, 1991). Performance has been established with long-term monitoring of the more than 200 facilities operated since the early 1980s. Rarely are NO_x reductions reported to be equal to or greater than 90 percent for utility boilers. 70- to 80-percent reductions are reported as representative performance levels for SCR (Robie, 1991).

OIL-/GAS-FIRED DRY-BOTTOM BOILERS

Average Baseline NO_x Emission Levels (All Boiler Designs)

0.37 lb/MMBtu (post-NSPS)
0.37 lb/MMBtu (pre-NSPS)

Combustion Controlled NO_x Levels (All Boiler Designs)

0.10 to 0.15 (0.13) lb/MMBtu (all boilers)

Reported NO_x Control Efficiency

Selective Noncatalytic Reduction (SNCR)—35- to 50-Percent NO_x Reduction from Uncontrolled Levels
25- to 40-Percent NO_x Reduction from Controlled Levels

NO_x reduction potential for combustion controlled boilers based on short-term data reported by SCE and SDG&E on the following boilers (Teixeira, 1992; Abele, 1989; Jones, 1991):

Morro Bay 330-MWe Unit 3 showed NO_x reductions of 30 to 40 percent with either aqueous ammonia or urea but with relatively high NH_3 slip (Teixeira, 1992).

Long Island Lighting Co. (LILCO) Port Jefferson 185-MWe Unit 3 NO_x was reduced 50 to 56 percent from uncontrolled NO_x levels of 0.29 to 0.33 lb/MMBtu with NSR approaching 2.0. With lower NSR and lower initial NO_x levels (0.22 to 0.25 lb/MMBtu), NO_x reductions were in the range of 36 to 48 percent (Teetz, 1992).

Experience reported by SCE on the retrofit of SNCR on 16 Southern California boilers showing 25- to 30-percent NO_x reduction from low, combustion-controlled levels (Springer, 1992). Some specific results include:

Encina 110-MWe Unit 2 burning natural with minimum NO_x levels in the range of 23 to 38 ppm over the load range of 40 to 100 percent of MCR.

Etiwanda 320-MWe Unit 3 oil-/gas-fired NO_x reduction of 30 percent over entire load range, with controlled NO_x emission in the range of 25 to 45 ppm.

SCE Huntington 215-MWe Unit 2 oil-/gas-fired showed NO_x reductions in the range of 25 to 40 percent from combustion controlled levels of 120 ppm over 60 to 100 percent of boiler load.

Selective Catalytic Reduction (SCR)—80-Percent NO_x Reduction from Uncontrolled Levels
70-Percent NO_x Reduction from Controlled Levels

NO_x reduction based on reported SCR performance for installations worldwide that shows reductions in the range of 70 to 80 percent (IEA, 1991). Performance has been established with long-term monitoring of over 200 facilities operated since the early 1980s. Rarely are NO_x reductions reported to be equal or greater than 90 percent. This control

alternative excludes the CAT-AH process, which has shown 50- to 64-percent NO_x reduction on SCE's Mandalay Unit 2 (Reese, 1992). Although still under demonstration, this SCR process represents a low-cost alternative to more conventional SCR installations targeted for more than 80-percent NO_x reduction.

APPENDIX E

SCR INSTALLATIONS ON COAL-FIRED PLANTS IN-USE OR FIRMLY PLANNED

(Source: IEA Coal Research, "NO_x Control Installations on Coal-Fired Plants," March 1991, pp. 39-43.)

Plant	Unit	MWe	Supplier	SCR loc§	Catalyst type	Catalyst form	% NO_x removal	Emissions, mg/m^3	N/R*	Start year
Austria										
Dürnrohr	1	405	Voest-Alpine, Babcock Hitachi KK	HD	TiO_2 based	plate	80	200	R	1986
Dürnrohr	2	320	Voest-Alpine, Babcock Hitachi KK	HD	TiO_2 based	plate	80	200	R	1986
Mellach		200	SGP-VA Energie, Mitsubishi Heavy Ind	HD	TiO_2 based	honeycomb	80	200	N	1986
Voitsberg	3	330	Babcock Hitachi KK, Kawasaki Heavy Ind	HD	TiO_2 based	honeycomb		150	R	1990
Denmark										
Amagervaerket	3	250	not known	TE	not known	not known	80	156	R	1998
Avedoerevaerket	1	250	Haldor Topsøe	HD	TiO_2 based	plate	80	156	R	1992
Federal Republic of Germany										
Altbach Deizisau	5	420	Steinmüller	HD	TiO_2 based	honeycomb	69	200	R	1985
Aschaffenburg	21	150	Thyssen Engineering	HD	TiO_2 based	plate	80	200	R	1990
Aschaffenburg	31	150	Thyssen Engineering	HD	TiO_2 based	plate	80	200	R	1990
BASF Ludwigshafen (Mitte)	250		Knauf Research Cottrell	TE	TiO_2 based	honeycomb		200	R	1990
BASF Marl		250	not known	TE	TiO_2 based	honeycomb		200		1989
Bergkamen	A	747	Energie- und Verfahrenstechnik	HD	TiO_2 based	honeycomb	75	200	R	1989
Bexbach	1	750	Energie- und Verfahrenstechnik	HD	TiO_2 based	honeycomb	77	200		1989
Buer		150	Steinmüller, NSK	HD	TiO_2 based	plate	75	200	R	1985
Charlottenburg	1	55	Steinmüller	TE	TiO_2 based	honeycomb	85	200	R	1990
Charlottenburg	2	55	Steinmüller	TE	TiO_2 based	honeycomb	85	200	R	1990
Charlottenburg	3	75	Steinmüller	TE	TiO_2 based	honeycomb	85	200	R	1990
Cuno (Herdecke)	2	96	Deutsche Babcock	TE	TiO_2 based	not known		200	N	1990
Datteln	1	48	Veba Kraftwerke Ruhr, NSK	TE	TiO_2 based	honeycomb		200	R	1989
Datteln	2	48	Veba Kraftwerke Ruhr, NSK	TE	TiO_2 based	honeycomb		200	R	1989
Datteln	3	48	Veba Kraftwerke Ruhr, NSK	TE	TiO_2 based	honeycomb		200	R	1989
Datteln	4	48	Veba Kraftwerke Ruhr, NSK	TE	TiO_2 based	honeycomb		200	R	1989
Datteln	5	97	Didier	TE	FeO_2 based	not known		200		1989
Dormagen, Bayer	7	37	Deutsche Babcock	HD	TiO_2 based	honeycomb		200	R	1989
DU Stadtmitte HKW II	A	70	Thyssen Engineering	TE	TiO_2 based	honeycomb	85	200	R	1989
DU Stadtmitte HKW II	B	140	Thyssen Engineering	TE	TiO_2 based	honeycomb	85	200	R	1989
Elverlingen	E3	258	Steinmüller	TE	TiO_2 based	honeycomb	86	200	R	1989
Elverlingen	E4	258	Steinmüller	TE	TiO_2 based	honeycomb		200	R	1989
Ensdorf	2	110	Knauf Research Cottrell	TE	TiO_2 based	honeycomb		200		1989
Ensdorf	3	300	Knauf Research Cottrell	TE	TiO_2 based	honeycomb		<200	R	1990
Farge		350	Uhde, Lentjes	HD	TiO_2 based	plate		200	R	1990
Fenne III		163	not known	HD	TiO_2 based	plate		200	R	1990
Flingern I	1-2	46	Lentjes, Steinmüller, Hugo Petersen	TE	TiO_2 based	honeycomb		200	R	1990
Flingern II	3-4	67	Lentjes, Steinmüller, Hugo Petersen	TE	TiO_2 based	honeycomb		200	R	1990
Franken II	1	200	Thyssen Engineering, KWU	HD	TiO_2 based	plate		200	R	1990
Franken II	2	200	Thyssen Engineering, KWU	HD	TiO_2 based	plate		200	R	1990
Frankfurt Höchst	1	44	Knauf Research Cottrell	TE	TiO_2 based	not known	>78	200	R	1991
Frankfurt Höchst	2	44	Knauf Research Cottrell	TE	TiO_2 based	not known		200	R	1991

§ HD = high dust; LD = low dust; TE = tail end

* N/R = New or Retrofit

Plant	Unit	MWe	Supplier	SCR loc§	Catalyst type	Catalyst form	NO_x removal	Emissions, mg/m³	N/R*	Start year
Frankfurt West	2	90	Lentjes	HD	TiO_2 based	not known	80	200	N	1989
Frankfurt West	3	90	Lentjes	HD	TiO_2 based	not known	80	200	N	1989
Garath		20	Steinmüller, Hugo Petersen	TE	activated lignite coke	pellets		200	R	1987
Hafen (Bremen)	5	150	Energie- und Verfahrenstechnik	HD	TiO_2 based	plate	85	200		1990
Hafen (Bremen)	6	300	Energie- und Verfahrenstechnik	HD	TiO_2 based	plate	85	200		1990
Hafen (Hamburg)	2	85	Steinmüller	TE	TiO_2 based	honeycomb	75	200	N	1987
Hannover-Stöcken	1	130	Uhde, Lentjes	TE	TiO_2 based	honeycomb		200	R	1989
Hannover-Stöcken	2	130	Uhde, Lentjes	TE	TiO_2 based	honeycomb		200	R	1989
Hastedt (Bremen)	15	130	Energie- und Verfahrenstechnik	HD	TiO_2 based	honeycomb	70	200	N	1989
Heilbronn	3	110	Deutsche Babcock	TE	TiO_2 based	honeycomb	>80	200	R	1990
Heilbronn	4	110	Deutsche Babcock	TE	TiO_2 based	honeycomb	>80	200	R	1990
Heilbronn	5	125	Deutsche Babcock	TE	TiO_2 based	honeycomb	>80	200	R	1990
Heilbronn	6	125	Deutsche Babcock	TE	TiO_2 based	honeycomb	>80	200	R	1990
Heilbronn	7	750	Energie- und Verfahrenstechnik	HD	TiO_2 based	honeycomb	>80	200	R	1986
Herne	1	150	Uhde, Lentjes	TE	TiO_2 based	honeycomb	>80	200	R	1989
Herne	2	150	Uhde, Lentjes	TE	TiO_2 based	honeycomb	>80	200	R	1989
Herne	3	300	Uhde, Lentjes	TE	TiO_2 based	honeycomb	>80	200	R	1989
Heyden	4	800	Uhde, Lentjes	HD	TiO_2 based	not known	75	200	R	1988
Ibbenbüren	B	770	Uhde, Lentjes	TE	TiO_2 based	honeycomb		<200	R	1988
Karlsruhe West	3	64	Krupp Koppers	TE	TiO_2 based	honeycomb		200	R	1988
Kellermann (Lünen)	K10	150	Lentjes	TE	TiO_2 based	honeycomb	>80	200	R	1989
Kiel Ost		350	Uhde, Lentjes	HD	TiO_2 based	honeycomb	80	200	R	1989
Knepper	C	375	Uhde, Lentjes, Thyssen Engineering	HD	TiO_2 based	plate	90	200	R	1986
Kraftwerk Hüls I	4	125	Knauf Research Cottrell	TE	TiO_2 based	honeycomb		200	R	1990
Kraftwerk Hüls I	5	131	Knauf Research Cottrell	TE	TiO_2 based	honeycomb		200	R	1991
Kraftwerk Hüls II	3	84	Thyssen Engineering	TE	TiO_2 based	honeycomb		200	R	1990
Lausward	A	127	Lentjes, Steinmüller, Hugo Petersen	TE	TiO_2 based	honeycomb		200	R	1989
Lausward	B	127	Lentjes, Steinmüller, Hugo Petersen	TE	TiO_2 based	honeycomb	80	200	R	1989
Lausward	C	127	Lentjes, Steinmüller; Hugo Petersen	TE	TiO_2 based	honeycomb	80	200	R	1989
Lausward	D	127	Lentjes, Steinmüller, Hugo Petersen	TE	TiO_2 based	honeycomb	80	200	R	1989
Mainz	2	100	Deutsche Babcock	TE	TiO_2 based	honeycomb		200	R	1988
Mainz	3	100	Deutsche Babcock	TE	TiO_2 based	honeycomb		200	R	1988
Mannheim	3	220	Deutsche Babcock	TE	TiO_2 based	honeycomb		200	R	1988
Mannheim	4	220	Deutsche Babcock	TE	TiO_2 based	honeycomb		200	R	1988
Mannheim	7(K18)	475	Energie- und Verfahrenstechnik	HD	TiO_2 based	honeycomb	75	200	R	1988
Mannheim	8(K19)	480	Energie- und Verfahrenstechnik	HD	TiO_2 based	honeycomb	85	200	N	1992
Mehrum	3	700	Uhde, Lentjes, Hitachi	HD	TiO_2 based	plate	75	200	R	1988
Mitte	1	87	Knauf Research Cottrell	TE	TiO_2 based	not known		200	R	1988
Münster (Stuttgart)	12	40	Energie- und Verfahrenstechnik	HD	TiO_2 based	honeycomb	80	200	R	1986
Münster (Stuttgart)	15	40	Energie- und Verfahrenstechnik	HD	TiO_2 based	honeycomb	80	200	R	1986
Münster (Stuttgart)	25	67	Energie- und Verfahrenstechnik	HD	TiO_2 based	honeycomb	72	200	R	1986
Nord (München)	2	362	Deutsche Babcock	HD	TiO_2 based	plate		100	N	1992
Oberhavel	1	100	Steinmüller	HD	TiO_2 based	not known		200	R	1990
Oberhavel	2	100	Steinmüller	HD	TiO_2 based	not known		200	R	1990
Ost (Lünen)	K11	350	Lentjes	TE	TiO_2 based	honeycomb	>80	200	R	1989
Porta WF Veltheim	1	100	Deutsche Babcock	HD	TiO_2 based	plate	82	200	R	1989
Porta WF Veltheim	2	100	Deutsche Babcock	HD	TiO_2 based	plate		200	R	1989
Porta WF Veltheim	3	330	Deutsche Babcock	HD	TiO_2 based	plate		200	R	1989
Reuter	1	50	Lentjes	TE	TiO_2 based	not known		200	R	1990
Reuter	2	50	Lentjes	TE	TiO_2 based	not known		200	R	1990
Reuter	C	150	Lentjes	TE	TiO_2 based	not known		200	R	1990

§ HD = high dust; LD = low dust; TE = tail end

* N/R = New or Retrofit

				loc§	type	form	removal	mg/m³		year
Reuter West	D	300	Deutsche Babcock, Balcke, Dürr, Borsig	HD	TiO_2 based	honeycomb		200	N	1989
Reuter West	E	300	Deutsche Babcock, Balcke, Dürr, Borsig	HD	TiO_2 based	honeycomb		200	N	1989
Rheinhafen (Karlsruhe)	7	550	Steinmüller	HD	TiO_2 based	honeycomb		200	R	1989
Rudow	1	38	Deutsche Babcock	HD	TiO_2 based	plate		200	R	1990
Rudow	2	38	Deutsche Babcock	TE	TiO_2 based	honeycomb		200	R	1990
Rudow	3	100	Deutsche Babcock	TE	TiO_2 based	not known		200	R	1990
Rüsselsheim, Adam Opel AG	2	20	Lurgi	TE	TiO_2 based	honeycomb	85	200	R	1990
Rüsselsheim, Adam Opel AG	3	20	Lurgi	TE	TiO_2 based	honeycomb	85	200	R	1990
Sandreuth	1	35	Linde, Werksgruppe TVT München	TE	zeolite	pellets		200	R	1987
Sandreuth	2	35	Linde, Werksgruppe TVT München	TE	zeolite	pellets		200	R	1987
Sandreuth	3	35	Linde, Werksgruppe TVT München	TE	zeolite	pellets		200	R	1987
Scholven	B	370	Veba Kraftwerke Ruhr, KWU	HD	TiO_2 based	plate		200	R	1989
Scholven	C	370	Veba Kraftwerke Ruhr, KWU	HD	TiO_2 based	plate		200	R	1990
Scholven	D	370	Veba Kraftwerke Ruhr, KWH	HD	TiO_2 based	plate		200	R	1990
Scholven	E	370	Veba Kraftwerke Ruhr, KWU	HD	TiO_2 based	plate		200	R	1990
Scholven	F	740	BASF	HD	TiO_2 based	honeycomb		200	R	1989
Schwandorf	B	100	Uhde, Lentjes	HD	TiO_2 based	plate	70	≤200	R	1990
Schwandorf	C	100	Uhde, Lentjes	HD	TiO_2 based	plate	70	≤200	R	1988
Schwandorf	D	300	Uhde, Lentjes	HD	TiO_2 based	plate	70	≤200	R	1988
Shamrock	1	83	Veba Kraftwerke Ruhr, NSK	TE	TiO_2 based	honeycomb		200	R	1990
Shamrock	2	83	Veba Kraftwerke Ruhr, NSK	TE	TiO_2 based	honeycomb		200	R	1990
Shamrock	3	39	Veba Kraftwerke Ruhr, NSK	TE	TiO_2 based	honeycomb		200	R	1990
Shamrock	4	39	Veba Kraftwerke Ruhr, NSK	TE	TiO_2 based	honeycomb		200	R	1990
Siersdorf		180	Lentjes	TE	TiO_2 based	honeycomb		200	R	1990
Staudinger	1	250	Uhde, Lentjes	HD	TiO_2 based	not known		200	R	1990
Staudinger	2	250	Uhde, Lentjes	HD	TiO_2 based	plate		200	R	1990
Staudinger	3	300	Uhde, Lentjes	HD	FeO_2 based	plate		200	R	1990
Staudinger	5	500	Uhde, Lentjes	HD	TiO_2 based	not known		200	N	1990
Tiefstack	1	243	Steinmüller		TiO_2 based	not known		200	R	1992
Ürdingen, Bayer	1	85	Steinmüller	TE	TiO_2 based	honeycomb		200	R	1989
Ürdingen, Bayer	2	55	Steinmüller	TE	TiO_2 based	honeycomb		200	R	1989
Voerde	A	707	Knauf Research Cottrell	HD	TiO_2 based	honeycomb	80	200	R	1989
Voerde	B	707	Knauf Research Cottrell	HD	TiO_2 based	honeycomb	80	200	R	1989
Völklingen		230	Deutsche Babcock	HD	TiO_2 based	plate		200	R	1989
Walheim	1	105	Steinmüller	HD	TiO_2 based	not known	79	200	R	1987
Walheim	2	150	Steinmüller	HD	TiO_2 based	honeycomb	84	200	R	1989
Walsum	7	150	Uhde, Lentjes	LD	TiO_2 based	plate	>80	200	R	1988
Walsum	9	410	Uhde, Lentjes	HD	TiO_2 based	plate	70	200	N	1988
Wedel	1	107	Steinmüller	HD	TiO_2 based	honeycomb	80	200	R	1987
Wedel	2	107	Steinmüller	HD	TiO_2 based	honeycomb	80	200	R	1988
Weiher II	1	150	not known	TE	TiO_2 based	not known		200	R	1989
Weiher II	2	150	not known	TE	TiO_2 based	not known		200	R	1989
Weiher III		707	Steinmüller	HD	TiO_2 based	honeycomb		200	R	1989
Werne	K	750	Steinmüller	TE	TiO_2 based	honeycomb		200	R	1990
West Voerde	1	350	Uhde, Lentjes	TE	TiO_2 based	honeycomb	>80	200	R	1989
West Voerde	2	350	Uhde, Lentjes	TE	TiO_2 based	honeycomb	>80	200	R	1989
West (VW)	1	140	Uhde, Lentjes	TE	TiO_2 based	honeycomb		200	R	1989
West (VW)	2	140	Uhde, Lentjes	TE	TiO_2 based	honeycomb		200	R	1989
Westerholt	1	150	Veba Kraftwerke Ruhr, BASF	TE	TiO_2 based	honeycomb		200	R	1989
Westerholt	2	150	Veba Kraftwerke Ruhr, BASF	TE	TiO_2 based	honeycomb		200	R	1989
Westfalen	A	176	Steinmüller	TE	TiO_2 based	honeycomb		200	R	1991
Westfalen	B	176	Steinmüller	TE	TiO_2 based	honeycomb		200	R	1991

§ HD = high dust; LD = low dust; TE = tail end

* N/R = New or Retrofit

Plant	Unit	MWe	Supplier	SCR loc§	Catalyst type	Catalyst form	SO2 removal	Emissions mg/m³	N/R*	Start year
Westfalen	C	320	Steinmüller	TE	TiO_2 based	honeycomb		200	R	1991
Wilhelmshaven		750	Uhde, Lentjes	HD	FeO_2 based (50%)	honeycomb		200	R	1988
Zolling Leiningerwerk	5	450	Uhde, Lentjes	HD	TiO_2 based	plate	70	200	R	1988
Finland										
Meri-Pori		560	Tampella	HD	TiO_2 based	plate	80	<200	N	1993
Italy										
Brindisi Sud	1	660	not known	HD	not known	not known	80	<200	N	1992
Brindisi Sud	2	660	not known	HD	not known	not known	80	<200	N	1993
Brindisi Sud	3	660	not known	HD	not known	not known	80	<200	N	1993
Brindisi Sud	4	660	not known	HD	not known	not known	80	<200	N	1994
Fiume Santo	3	320	not known	HD	not known	not known	80	<200	N	1992
Fiume Santo	4	320	not known	HD	not known	not known	80	<200	N	1992
Fusina	1	160	not known	HD	not known	not known	80	<200	R	1992
Fusina	2	160	not known	HD	not known	not known	80	<200	R	1992
Fusina	3	320	not known	HD	not known	not known	80	<200	R	1993
Fusina	4	320	not known	HD	not known	not known	80	<200	R	1993
Gioia Tauro	1	660	not known	HD	not known	not known	80	<200	N	1994
Gioia Tauro	2	660	not known	HD	not known	not known	80	<200	N	1995
Gioia Tauro	3	660	not known	HD	not known	not known	80	<200	N	1995
Gioia Tauro	4	660	not known	HD	not known	not known	80	<200	N	1996
La Spezia	1	320	not known	HD	not known	not known	80	<200	R	1992
La Spezia	2	320	not known	HD	not known	not known	80	<200	R	1992
La Spezia	3	600	not known	HD	not known	not known	80	<200	R	1993
La Spezia	4	600	not known	HD	not known	not known	80	<200	R	1993
San Filippo Del Mela	5	320	not known	HD	not known	not known	80	<200	R	1994
San Filippo Del Mela	6	320	not known	HD	not known	not known	80	<200	R	1994
Sulcis	1	240	not known	HD	not known	not known	80	<200	R	1994
Sulcis	2	240	not known	HD	not known	not known	80	<200	R	1994
Sulcis	3	240	not known	HD	not known	not known	80	<200	R	1994
Tavazzano	3	320	not known	HD	not known	not known	80	<200	R	1994
Tavazzano	4	320	not known	HD	not known	not known	80	<200	R	1995
Vado Ligure	1	320	not known	HD	not known	not known	80	<200	R	1993
Vado Ligure	2	320	not known	HD	not known	not known	80	<200	R	1993
Vado Ligure	3	320	not known	HD	not known	not known	80	<200	R	1994
Vado Ligure	4	320	not known	HD	not known	not known	80	<200	R	1994
Japan										
Chiba Factory	2	90	Mitsubishi Heavy Industries		TiO_2 based	honeycomb				1985
Daicel Chemical Co, Aboshi Factory		100	Mitsubishi Heavy Industries		TiO_2 based	honeycomb				1987
Hekinan	2	700	Mitsubishi Heavy Industries		TiO_2 based	honeycomb	80		N	1992
Hekinan	3	700	Ishikawajima Harima Heavy Ind	HD	TiO_2 based	honeycomb	80		N	1993
Himeji No 1	1	33	Ishikawajima Harima Heavy Ind		TiO_2 based	honeycomb	75		R	1982
Idemitsu Kosan Engineering Co	A	50	Kawasaki Heavy Industries		TiO_2 based	not known	>55			1987
Idemitsu Kosan Petroleum, Hyogo Refinery		40	Babcock Hitachi KK	HD	TiO_2 based	plate	60			1986

§ HD = high dust; LD = low dust; TE = tail end

* N/R = New or Retrofit

			Supplier	SCR loc§	Catalyst type	Catalyst form	% NO_x removal	Emissions, mg/m^3	N/R*	Start year
Matsuura (Kyushu Electric Power)	1	700	Mitsubishi Heavy Industries	HD	TiO_2 based	honeycomb			N	1989
Matsuura (EPDC)	1	1000	Babcock Hitachi KK	LD	TiO_2 based	plate	80	123	N	1990
Matsuura	2	1000	not known	LD	TiO_2 based	plate			N	1999
Minato	1	156	Mitsubishi Heavy Industries	HD	TiO_2 based	honeycomb	53		R	1983
Mizushima	1	125	Babcock Hitachi KK	HD	TiO_2 based	plate	65		R	1984
Mizushima	2	156	Babcock Hitachi KK	HD	TiO_2 based	plate	65		R	1984
Nakoso	8	600	Mitsubishi Heavy Industries	HD	TiO_2 based	honeycomb	60		N	1983
Nakoso	9	600	Ishikawajima Harima Heavy Ind	HD	TiO_2 based	honeycomb	60		N	1983
Saijo	1	156	Mitsubishi Heavy Industries	HD	TiO_2 based	honeycomb	65		R	1983
Saijo	2	250	Ishikawajima Harima Heavy Ind	HD	TiO_2 based	honeycomb	65		R	1984
Sakata	1	350	Mitsubishi Heavy Industries	HD	TiO_2 based	honeycomb	80		R	1984
Sakata	2	350	Mitsubishi Heavy Industries	HD	TiO_2 based	honeycomb	35		N	1984
Sendai	2	175	Babcock Hitachi KK	HD	TiO_2 based	plate	60		R	1983
Sendai	3	175	Babcock Hitachi KK	HD	TiO_2 based	plate	60		R	1983
Shimonoseki	1	175	Mitsubishi Heavy Industries	HD	TiO_2 based	honeycomb	50		R	1981
Shin Onoda	1	500	Ishikawajima Harima Heavy Ind	HD	TiO_2 based	honeycomb	80		N	1986
Shin Onoda	2	500	Ishikawajima Harima Heavy Ind	HD	TiO_2 based	honeycomb	80		N	1987
Shin Ube	1	75	Mitsubishi Heavy Industries	HD	TiO_2 based	honeycomb	65		R	1982
Shin Ube	2	75	Mitsubishi Heavy Industries	HD	TiO_2 based	honeycomb	65		R	1981
Shin Ube	3	156	Mitsubishi Heavy Industries	HD	TiO_2 based	honeycomb	65		R	1981
Sumitomo Chemical Co, Chiba Factory	2	70	Mitsubishi Heavy Industries		TiO_2 based	honeycomb	80			1985
Sumitomo Metal Industries, Kokura Factory	1	20	Mitsubishi Heavy Industries		TiO_2 based	honeycomb	84			1985
Takeda Chemical Ind, Hikari Factory		30	Mitsubishi Heavy Industries		TiO_2 based	honeycomb	25			1986
Takehara	1	250	Babcock Hitachi KK, Kawasaki Heavy Ind	LD	TiO_2 based	honeycomb, plate	80	144	R	1981
Takehara	3	700	Babcock Hitachi KK	LD	TiO_2 based	plate	80	123	N	1983
Tomatoazuma	1	350	Babcock Hitachi KK	LD	TiO_2 based	plate	90		N	1980
Toray Industries Inc, Tokai Factory	4	30	Ishikawajima Harima Heavy Ind		TiO_2 based	not known				1988
Toyama Kyodo Shinko	1	200	Babcock Hitachi KK	HD	TiO_2 based	plate	60		R	1984
Toyama Kyodo Shinko	2	200	Babcock Hitachi KK	HD	TiO_2 based	plate	60		R	1984
Tsuruga	1	500	Mitsubishi Heavy Industries		TiO_2 based	honeycomb				1990
Ube Industries			Kawasaki Heavy Industries		TiO_2 based	not known	38			1982
Yokosuka	1	265	Mitsubishi Heavy Industries	HD	TiO_2 based	honeycomb	70		R	1985
Yokosuka	2	265	Mitsubishi Heavy Industries	HD	TiO_2 based	honeycomb	70		R	1985
Netherlands										
Gelderland	12	125	ESTS	HD	TiO_2 based	honeycomb	80	100	R	1987
Sweden										
Västerås	1	40	Fläkt	HD	TiO_2 based	plate	84	280	R	1991
Västerås	2	40	Fläkt	HD	TiO_2 based	plate	84	280	R	1991

§ HD = high dust; LD = low dust; TE = tail end

* N/R = New or Retrofit

APPENDIX F

NO_x CONTROL COSTS

PC-FIRED AND CYCLONE BOILERS

The enclosed spreadsheets include cost estimates for the following test cases:

1. Overfire air (OFA) for wall-fired boilers
2. Low-NO_x burners (LNB) for wall-fired boilers
3. Low-NO_x burners (LNB) for tangential-fired boilers
4. Low-NO_x burners (LNB) and overfire air (OFA) for wall-fired boilers
5. Low-NO_x burners (LNB) and overfire air (OFA) for tangential-fired boilers
6. Natural gas reburn (NGR) for wall-fired boilers
7. Natural gas reburn (NGR) for tangential-fired boilers
8. Natural gas reburn (NGR) for cyclone boilers
9. Selective noncatalytic reduction (SNCR) for wall-fired boilers (uncontrolled)
10. Selective noncatalytic reduction (SNCR) for wall-fired boilers (controlled)
11. Selective noncatalytic reduction (SNCR) for tangential-fired boilers (uncontrolled)
12. Selective noncatalytic reduction (SNCR) for tangential-fired boilers (controlled)
13. Selective catalytic reduction (SCR) for wall-fired boilers (uncontrolled)—cold side
14. Selective catalytic reduction (SCR) for wall-fired boilers (controlled)—cold side
15. Selective catalytic reduction (SCR) for tangential-fired boilers (uncontrolled)—cold side
16. Selective catalytic reduction (SCR) for tangential-fired boilers (controlled)—cold side
17. Selective catalytic reduction (SCR) for wall-fired boilers (controlled)—hot side
18. Selective catalytic reduction (SCR) for tangential-fired boilers (controlled)—hot side

Uncontrolled NO_x is taken as average of pre-NSPS current baseline emission levels (see Table 3-4). For wall-fired retrofit cost cases, the average emission levels for wall- and opposed-fired boilers are used. For controlled NO_x emission levels, both the high and low estimates provided in Tables 1-1 and 5-5 for pre-NSPS boilers are used to illustrate the sensitivity of cost effectiveness to control efficiency. For FGT controls, the upper level of the NO_x range estimated for LNB-based controls is used as the baseline from which further NO_x reductions are achieved. For comparison, cost cases for FGT controls on uncontrolled units are also presented.

NOx CONTROL COSTS - COAL BOILERS clwofa.wk1 OVERFIRE AIR - PC WALL-FIRED UNITS (Sorge, 1992) Case 1 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	15.74	11.93	10.14	9.04	7.40	11.93	11.93	11.93	11.93
-GENERAL FACILITIES (GF) 10% of PCC	1.57	1.19	1.01	0.90	0.74	1.19	1.19	1.19	1 19
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	1.57	1.19	1.01	0.90	0.74	1.19	1.19	1.19	1.19
-PROCESS CONTINGENCY (Proc) 10% of PCC	1.57	1.19	1.01	0.90	0.74	1.19	1.19	1 19	1.19
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	5.67	4.30	3.65	3.26	2.66	4.30	4.30	4.30	4.30
TOTAL PLANT COSTS (TPC) (1991$/kW) =	26	20	17	15	12	20	20	20	20
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	26	20	17	15	12	20	20	20	20
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0 00
-PREPRODUCTION COSTS 2% of TPC	0.52	0.40	0.34	0.30	0.25	0.40	0.40	0.40	0.40
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	27	20	17	15	13	20	20	20	20
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)									
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	0.523	0.396	0.337	0.300	0.246	0.396	0.396	0 396	0 396
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.063	0.048	0.040	0.036	0.029	0 048	0.048	0 048	0.048
FIXED O & M COSTS ($/kW-yr) =	0.38	0.29	0.25	0.22	0.18	0 18	0.36	0.29	0 29
VARIABLE O & M COSTS (mills/kW-hr) =	0.036	0.027	0.023	0.021	0.017	0.076	0.011	0.027	0 027

NOx CONTROL COSTS - COAL BOILERS clwofa.wk1 OVERFIRE AIR - PC WALL-FIRED UNITS (Sorge, 1992) Case 1 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	1161	2322	3484	4645	7664	1429	2930	2322	2322
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FUEL COSTS									
-COAL (mills/kW-hr)	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.067	0.051	0.043	0.038	0.031	0.051	0.051	0.051	0.051
-VARIABLE O & M (mills/kW-Hr)	0.036	0.027	0.023	0.021	0.017	0.076	0.011	0.027	0.027
-CONSUMABLES (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-FUEL (mills/kW-Hr)	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	3.13	2.37	2.02	1.80	1.47	2.37	2.37	2.14	3.29
LEVELIZED BUSBAR COST (mills/kW-hr) =	0.75	0.59	0.51	0.47	0.40	0.90	0.49	0.55	0.75
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
-LOWER CONTROLLED NOx (lb/MMBtu)	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
-LOWER NOx REDUCTION (tons/yr)	759	1519	2278	3038	5012	935	1916	1519	1519
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	559	441	385	351	300	673	364	411	561
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
-HIGHER NOx REDUCTION (tons/yr)	456	911	1367	1823	3007	561	1150	911	911
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	932	735	642	585	500	1121	607	684	936

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS c2wlnb.wk1	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
LOW NOx BURNERS - PC WALL-FIRED UNITS (Figure 6-4) Case 2 | SIZE (MW)	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	15.42	11.69	9.94	8.86	7.25	11.69	11.69	11.69	11.69
-GENERAL FACILITIES (GF) 10% of PCC	1.54	1.17	0.99	0.89	0.73	1.17	1.17	1.17	1.17
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	1.54	1.17	0.99	0.89	0.73	1.17	1.17	1.17	1.17
-PROCESS CONTINGENCY (Proc) 10% of PCC	1.54	1.17	0.99	0.89	0.73	1.17	1.17	1.17	1.17
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	5.55	4.21	3.58	3.19	2.61	4.21	4.21	4.21	4 21
TOTAL PLANT COSTS (TPC) (1991$/kW) =	26	19	16	15	12	19	19	19	19
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	26	19	16	15	12	19	19	19	19
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0 00
-PREPRODUCTION COSTS 2% of TPC	0.51	0.39	0.33	0.29	0.24	0.39	0.39	0 39	0 39
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	26	20	17	15	12	20	20	20	20
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)									
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	0.512	0.388	0.330	0.294	0.241	0.388	0.388	0.388	0 388
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.061	0.047	0.040	0.035	0.029	0.047	0.047	0.047	0 047
FIXED O & M COSTS ($/kW-yr) =	0.37	0.28	0.24	0.21	0.18	0.17	0.36	0 28	0.28
VARIABLE O & M COSTS (mills/kW-hr) =	0.035	0.027	0.023	0.020	0.017	0.074	0.011	0 027	0 027

NOx CONTROL COSTS - COAL BOILERS c2wlnb.wkl LOW NOx BURNERS - PC WALL-FIRED UNITS (Figure 6-4) Case 2 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	581	1161	1742	2322	3832	715	1465	1161	1161
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FUEL COSTS									
-COAL (mills/kW-hr)	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.065	0.050	0.042	0.038	0.031	0.050	0.050	0.050	0.050
-VARIABLE O & M (mills/kW-Hr)	0.035	0.027	0.023	0.020	0.017	0.074	0.011	0.027	0.027
-CONSUMABLES (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-FUEL (mills/kW-Hr)	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	3.07	2.32	1.98	1.76	1.44	2.32	2.32	2.10	3.22
LEVELIZED BUSBAR COST (mills/kW-hr) =	0.69	0.53	0.46	0.41	0.35	0.83	0.43	0.49	0.69
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
-LOWER CONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0 45
-LOWER NOx REDUCTION (tons/yr)	1519	3038	4557	6075	10025	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	257	199	172	155	130	313	162	184	258
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-HIGHER NOx REDUCTION (tons/yr)	1063	2126	3190	4253	7017	1309	2683	2126	2126
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	367	285	246	222	186	447	231	263	369

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS c3tlnb.wk1 LOW NOx BURNERS - PC TANGENTIAL-FIRED (Manaker, 1992) Case 3 | SIZE (MW)	EFFECT OF CAPACITY 100	150	200	300	375	EFFECT OF C.F. 200	200	EFFECT OF AGE 200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	18119	24159	36239	45298	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	18.93	16.10	14.35	12.20	11.16	14.35	14.35	14.35	14.35
-GENERAL FACILITIES (GF) 10% of PCC	1.89	1.61	1.43	1.22	1.12	1.43	1.43	1.43	1 43
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	1.89	1.61	1.43	1.22	1.12	1.43	1.43	1.43	1.43
-PROCESS CONTINGENCY (Proc) 10% of PCC	1.89	1.61	1.43	1.22	1.12	1.43	1.43	1.43	1.43
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	6.82	5.79	5.16	4.39	4.02	5.16	5.16	5.16	5.16
TOTAL PLANT COSTS (TPC) (1991$/kW) =	31	27	24	20	19	24	24	24	24
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	31	27	24	20	19	24	24	24	24
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-PREPRODUCTION COSTS 2% of TPC	0.63	0.53	0.48	0.41	0.37	0.48	0.48	0.48	0 48
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	32	27	24	21	19	24	24	24	24
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)									
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	0.629	0.534	0.476	0.405	0.370	0.476	0 476	0.476	0 476
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.075	0.064	0.057	0.049	0.044	0.057	0 057	0.057	0 057
FIXED O & M COSTS ($/kW-yr) =	0.46	0.39	0.35	0.29	0.27	0.21	0.44	0.35	0.35
VARIABLE O & M COSTS (mills/kW-hr) =	0.043	0.037	0.033	0.028	0 026	0.091	0 013	0.033	0.033

NOx CONTROL COSTS - COAL BOILERS c3tlnb.wk1 LOW NOx BURNERS - PC TANGENTIAL-FIRED (Manaker, 1992) Case 3 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	581	871	1161	1742	2177	715	1465	1161	1161
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FUEL COSTS									
-COAL (mills/kW-hr)	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.080	0.068	0.061	0.052	0.047	0.061	0.061	0.061	0.061
-VARIABLE O & M (mills/kW-Hr)	0.043	0.037	0.033	0.028	0.026	0.091	0.013	0.033	0.033
-CONSUMABLES (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-FUEL (mills/kW-Hr)	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	3.77	3.20	2.85	2.43	2.22	2.85	2.85	2.58	3.95
LEVELIZED BUSBAR COST (mills/kW-hr) =	0.83	0.71	0.64	0.55	0.51	1.01	0.52	0.59	0.83
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
-LOWER NOx REDUCTION (tons/yr)	608	911	1215	1823	2278	748	1533	1215	1215
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	779	669	601	518	477	950	486	556	782
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-HIGHER NOx REDUCTION (tons/yr)	456	683	911	1367	1709	561	1150	911	911
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1039	892	802	690	636	1266	648	741	1043

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS c4wlnof.wkl LNB + OFA - PC WALL-FIRED UNITS (Sorge, 1992) Case 4 | SIZE (MW)	EFFECT OF CAPACITY 100	200	300	400	660	EFFECT OF C.F. 200	200	EFFECT OF AGE 200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	31.48	23.86	20.28	18.08	14.80	23.86	23.86	23.86	23.86
-GENERAL FACILITIES (GF) 10% of PCC	3.15	2.39	2.03	1.81	1.48	2.39	2.39	2.39	2.39
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	3.15	2.39	2.03	1.81	1.48	2.39	2.39	2.39	2.39
-PROCESS CONTINGENCY (Proc) 10% of PCC	3.15	2.39	2.03	1.81	1.48	2.39	2.39	2.39	2.39
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	11.33	8.59	7.30	6.51	5.33	8.59	8.59	8.59	8.59
TOTAL PLANT COSTS (TPC) (1991$/kW) =	52	40	34	30	25	40	40	40	40
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	52	40	34	30	25	40	40	40	40
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-PREPRODUCTION COSTS 2% of TPC	1.05	0.79	0.67	0.60	0.49	0.79	0.79	0.79	0.79
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	53	40	34	31	25	40	40	40	40
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)									
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	1.045	0.792	0.673	0.600	0.491	0.792	0.792	0.792	0.792
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.125	0.095	0.081	0.072	0.059	0.095	0.095	0.095	0.095
FIXED O & M COSTS ($/kW-yr) =	0.76	0.58	0.49	0.44	0.36	0.35	0.73	0.58	0.58
VARIABLE O & M COSTS (mills/kW-hr) =	0.072	0.055	0.046	0.041	0.034	0.152	0.022	0.055	0.055

NOx CONTROL COSTS - COAL BOILERS c4wlnof.wk1 LNB + OFA - PC WALL-FIRED UNITS (Sorge, 1992) Case 4 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	1161	2322	3484	4645	7664	1429	2930	2322	2322
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FUEL COSTS									
-COAL (mills/kW-hr)	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.134	0.101	0.086	0.077	0.063	0.101	0.101	0.101	0.101
-VARIABLE O & M (mills/kW-Hr)	0.072	0.055	0.046	0.041	0.034	0.152	0.022	0.055	0.055
-CONSUMABLES (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-FUEL (mills/kW-Hr)	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	6.26	4.74	4.03	3.60	2.94	4.74	4.74	4.28	6.57
LEVELIZED BUSBAR COST (mills/kW-hr) =	1.40	1.08	0.93	0.84	0.71	1.70	0.88	1.00	1.40
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
-LOWER CONTROLLED NOx (lb/MMBtu)	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
-LOWER NOx REDUCTION (tons/yr)	1823	3645	5468	7291	12029	2243	4599	3645	3645
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	437	338	292	263	221	531	274	313	439
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
-HIGHER NOx REDUCTION (tons/yr)	1215	2430	3645	4860	8020	1496	3066	2430	2430
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	655	507	438	395	331	797	411	469	658

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS c5tlnso.wkl LNB + SOFA - PC TANGENTIAL-FIRED UNITS (Figure 6-5) Case 5 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	18119	24159	36239	45298	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	23.11	19.65	17.51	14.89	13.62	17.51	17.51	17.51	17.51
-GENERAL FACILITIES (GF) 10% of PCC	2.31	1.96	1.75	1.49	1.36	1.75	1.75	1.75	1.75
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	2.31	1.96	1.75	1.49	1.36	1.75	1.75	1.75	1.75
-PROCESS CONTINGENCY (Proc) 10% of PCC	2.31	1.96	1.75	1.49	1.36	1.75	1.75	1.75	1.75
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	8.32	7.07	6.30	5.36	4.90	6.30	6.30	6.30	6.30
TOTAL PLANT COSTS (TPC) (1991$/kW) =	38	33	29	25	23	29	29	29	29
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	38	33	29	25	23	29	29	29	29
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-PREPRODUCTION COSTS 2% of TPC	0.77	0.65	0.58	0.49	0.45	0.58	0.58	0.58	0.58
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	39	33	30	25	23	30	30	30	30
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)									
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	0.767	0.652	0.581	0.494	0.452	0.581	0.581	0.581	0.581
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.092	0.078	0.070	0.059	0.054	0.070	0.070	0.070	0.070
FIXED O & M COSTS ($/kW-yr) =	0.56	0.47	0.42	0.36	0.33	0.26	0.53	0.42	0.42
VARIABLE O & M COSTS (mills/kW-hr) =	0.053	0.045	0.040	0.034	0.031	0.112	0.016	0.040	0.040

NOx CONTROL COSTS - COAL BOILERS c5tlnso.wk1 LNB + SOFA - PC TANGENTIAL-FIRED UNITS (Figure 6-5) Case 5 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	1161	1742	2322	3484	4355	1429	2930	2322	2322
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FUEL COSTS									
-COAL (mills/kW-hr)	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.098	0.083	0.074	0.063	0.058	0.074	0.074	0.074	0.074
-VARIABLE O & M (mills/kW-Hr)	0.053	0.045	0.040	0.034	0.031	0.112	0.016	0.040	0 040
-CONSUMABLES (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-FUEL (mills/kW-Hr)	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0.093	0 093
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	4.60	3.91	3.48	2.96	2.71	3.48	3.48	3.15	4.83
LEVELIZED BUSBAR COST (mills/kW-hr) =	1.05	0.91	0.82	0.71	0.66	1.27	0.67	0.76	1 06
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-LOWER NOx REDUCTION (tons/yr)	911	1367	1823	2734	3417	1122	2299	1823	1823
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	657	567	512	444	411	796	418	475	659
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-HIGHER NOx REDUCTION (tons/yr)	456	683	911	1367	1709	561	1150	911	911
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1314	1135	1024	888	822	1591	836	950	1319

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS c6wngr.wk1 NATURAL GAS REBURN - PC WALL UNITS (Farzan/EERC, 1991) Case 6 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)	22	22	22	22	22	22	22	22	22
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	29.56	22.40	19.05	16.98	13.89	22.40	22.40	22.40	22.40
-GENERAL FACILITIES (GF) 10% of PCC	2.96	2.24	1.90	1.70	1.39	2.24	2.24	2.24	2.24
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	2.96	2.24	1.90	1.70	1.39	2.24	2.24	2.24	2.24
-PROCESS CONTINGENCY (Proc) 20% of PCC	5.91	4.48	3.81	3.40	2.78	4.48	4.48	4.48	4 48
-PROJECT CONTING. (% of PCC+GF+EHOF+Proc) 30%	12.41	9.41	8.00	7.13	5.84	9.41	9.41	9.41	9.41
TOTAL PLANT COSTS (TPC) (1991$/kW) =	54	41	35	31	25	41	41	41	41
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	54	41	35	31	25	41	41	41	41
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00
-PREPRODUCTION COSTS 2% of TPC	1.08	0.82	0.69	0.62	0.51	0.82	0.82	0.82	0.82
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	55	42	35	32	26	42	42	42	42
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	1.075	0.815	0.693	0.617	0.505	0.815	0.815	0.815	0 815
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.102	0.071	0.056	0.047	0.034	0.071	0.071	0.071	0.071
FIXED O & M COSTS ($/kW-yr) =	0.71	0.52	0.43	0.37	0.29	0.32	0.65	0 52	0.52
VARIABLE O & M COSTS (mills/kW-hr) =	0.067	0.049	0.041	0.035	0.028	0.136	0.020	0.049	0.049

NOx CONTROL COSTS - COAL BOILERS c6wngr.wk1 NATURAL GAS REBURN - PC WALL UNITS (Farzan/EERC, 1991) Case 6 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	-756	-1512	-2268	-3024	-4989	-930	-1907	-1512	-1512
-COAL (tons/yr)	-33675	-67351	-101026	-134701	-222257	-41447	-84966	-67351	-67351
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	911325	1822649	2733974	3645299	6014743	1121630	2299342	1822649	1822649
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-SOLID/ASH WASTE DISPOSAL (mills/kW-hr)	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
FUEL COSTS									
-COAL (mills/kW-hr)	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	4.177	4.177	4.177	4.177	4.177	4.177	4.177	4.177	4.177
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.124	0.091	0.075	0.066	0.051	0.091	0.091	0.091	0.091
-VARIABLE O & M (mills/kW-Hr)	0.067	0.049	0.041	0.035	0.028	0.136	0.020	0.049	0.049
-CONSUMABLES (mills/kW-Hr)	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
-FUEL (mills/kW-Hr)	1.466	1.466	1.466	1.466	1.466	1.466	1.466	1.466	1.466
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	6.44	4.88	4.15	3.70	3.03	4.88	4 88	4.41	6.77
LEVELIZED BUSBAR COST (mills/kW-hr) =	2.62	2.29	2.14	2.04	1.90	2.91	2.08	2.21	2.62
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
-LOWER CONTROLLED NOx (lb/MMBtu)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
-LOWER NOx REDUCTION (tons/yr)	1671	3342	5012	6683	11027	2056	4215	3342	3342
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	891	780	728	696	649	993	710	752	893
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
-HIGHER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1089	954	890	851	793	1214	868	919	1092

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991
SOLID/ASH WASTE DISPOSAL ($/ton)	8.00	IAPCS, 1990

NOx CONTROL COSTS - COAL BOILERS c7tngr.wk1 NATURAL GAS REBURN - PC TANGENTIAL UNIT (Farzan/EERC, 1991) Case 7 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)	22	22	22	22	22	22	22	22	22
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	18119	24159	36239	45298	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	29.56	25.13	22.40	19.05	17.42	22.40	22.40	22.40	22.40
-GENERAL FACILITIES (GF) 10% of PCC	2.96	2.51	2.24	1.90	1.74	2.24	2.24	2.24	2.24
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	2.96	2.51	2.24	1.90	1.74	2.24	2.24	2.24	2.24
-PROCESS CONTINGENCY (Proc) 20% of PCC	5.91	5.03	4.48	3.81	3.48	4.48	4.48	4.48	4.48
-PROJECT CONTING. (% of PCC+GF+EHOF+Proc) 30%	12.41	10.56	9.41	8.00	7.32	9.41	9.41	9.41	9 41
TOTAL PLANT COSTS (TPC) (1991$/kW) =	54	46	41	35	32	41	41	41	41
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	54	46	41	35	32	41	41	41	41
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00
-PREPRODUCTION COSTS 2% of TPC	1.08	0.91	0.82	0.69	0.63	0.82	0.82	0.82	0 82
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	55	47	42	35	32	42	42	42	42
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	1.075	0.914	0.815	0.693	0.634	0.815	0.815	0.815	0 815
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.102	0.083	0.071	0.056	0.049	0.071	0.071	0 071	0 071
FIXED O & M COSTS ($/kW-yr) =	0.71	0.59	0.52	0.43	0.39	0.32	0.65	0.52	0.52
VARIABLE O & M COSTS (mills/kW-hr) =	0.067	0.056	0.049	0.041	0.036	0.136	0.020	0 049	0 049

NOx CONTROL COSTS - COAL BOILERS c7tngr.wk1 NATURAL GAS REBURN - PC TANGENTIAL UNIT (Farzan/EERC, 1991) Case 7 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	-756	-1134	-1512	-2268	-2835	-930	-1907	-1512	-1512
-COAL (tons/yr)	-33675	-50513	-67351	-101026	-126283	-41447	-84966	-67351	-67351
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	911325	1366987	1822649	2733974	3417468	1121630	2299342	1822649	1822649
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-SOLID/ASH WASTE DISPOSAL (mills/kW-hr)	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
FUEL COSTS									
-COAL (mills/kW-hr)	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	4.177	4.177	4.177	4.177	4.177	4.177	4.177	4.177	4.177
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.124	0.104	0.091	0.075	0.068	0.091	0.091	0.091	0.091
-VARIABLE O & M (mills/kW-Hr)	0.067	0.056	0.049	0.041	0.036	0.136	0.020	0.049	0.049
-CONSUMABLES (mills/kW-Hr)	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
-FUEL (mills/kW-Hr)	1.466	1.466	1.466	1.466	1.466	1.466	1.466	1.466	1.466
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	6.44	5.48	4.88	4.15	3.80	4.88	4 88	4.41	6 77
LEVELIZED BUSBAR COST (mills/kW-hr) =	2.62	2.41	2.29	2.14	2.06	2.91	2.08	2.21	2.62
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
-LOWER NOx REDUCTION (tons/yr)	1063	1595	2126	3190	3987	1309	2683	2126	2126
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1401	1293	1226	1145	1105	1560	1116	1182	1403
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
-HIGHER NOx REDUCTION (tons/yr)	759	1139	1519	2278	2848	935	1916	1519	1519
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1961	1810	1717	1603	1547	2184	1562	1655	1965

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991
SOLID/ASH WASTE DISPOSAL ($/ton)	8.00	IAPCS, 1990

NOx CONTROL COSTS - COAL BOILERS c8cngr.wk1 NATURAL GAS REBURN - PC CYCLONE UNITS (Farzan/EERC, 1991) Case 8 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	120	150	200	300	340	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	25	35
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	25	15
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.73	0.73	0.73	0.73	0.73	0.55	0.83	0.73	0.73
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)	22	22	22	22	22	22	22	22	22
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	14496	18119	24159	36239	41071	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.110	0.131
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	-----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	-----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	27.48	25.13	22.40	19.05	18.12	22.40	22.40	22.40	22.40
-GENERAL FACILITIES (GF) 10% of PCC	2.75	2.51	2.24	1.90	1.81	2.24	2.24	2.24	2.24
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	2.75	2.51	2.24	1.90	1.81	2.24	2.24	2.24	2.24
-PROCESS CONTINGENCY (Proc) 20% of PCC	5.50	5.03	4.48	3.81	3.62	4.48	4.48	4.48	4.48
-PROJECT CONTING. (% of PCC+GF+EHOF+Proc) 30%	11.54	10.56	9.41	8.00	7.61	9.41	9.41	9.41	9.41
TOTAL PLANT COSTS (TPC) (1991$/kW) =	50	46	41	35	33	41	41	41	41
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	50	46	41	35	33	41	41	41	41
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-PREPRODUCTION COSTS 2% of TPC	1.00	0.91	0.82	0.69	0.66	0.82	0.82	0.82	0.82
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	51	47	42	35	34	42	42	42	42
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0 089	-0.089	-0.089
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	0.999	0.914	0.815	0.693	0.659	0.815	0.815	0.815	0 815
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.093	0.083	0.071	0.056	0.052	0.071	0.071	0.071	0.071
FIXED O & M COSTS ($/kW-yr) =	0.73	0.66	0.58	0.48	0.45	0.44	0.66	0.58	0 58
VARIABLE O & M COSTS (mills/kW-hr) =	0.042	0.038	0.034	0.028	0.026	0.074	0.019	0.034	0.034

NOx CONTROL COSTS - COAL BOILERS c8cngr.wk1 NATURAL GAS REBURN - PC CYCLONE UNITS (Farzan/EERC, 1991) Case 8 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	120	150	200	300	340	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	-1019	-1273	-1698	-2547	-2887	-1279	-1931	-1698	-1698
-COAL (tons/yr)	-45384	-56730	-75640	-113460	-128588	-56989	-86002	-75640	-75640
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	1228185	1535232	2046975	3070463	3479858	1542242	2327383	2046975	2046975
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-SOLID/ASH WASTE DISPOSAL (mills/kW-hr)	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
FUEL COSTS									
-COAL (mills/kW-hr)	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	4.177	4.177	4.177	4.177	4.177	4.177	4.177	4.177	4.177
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.115	0.104	0.091	0.075	0.071	0.091	0.091	0.091	0.091
-VARIABLE O & M (mills/kW-Hr)	0.042	0.038	0.034	0.028	0.026	0.074	0.019	0.034	0.034
-CONSUMABLES (mills/kW-Hr)	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
-FUEL (mills/kW-Hr)	1.466	1.466	1.466	1.466	1.466	1.466	1.466	1.466	1.466
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	5.99	5.48	4.88	4.15	3.95	4.88	4.88	4.58	5.47
LEVELIZED BUSBAR COST (mills/kW-hr) =	2.39	2.29	2.18	2.04	2.01	2.47	2.07	2.13	2.27
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
-LOWER CONTROLLED NOx (lb/MMBtu)	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
-LOWER NOx REDUCTION (tons/yr)	3193	3992	5322	7983	9048	4010	6051	5322	5322
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	573	551	524	491	482	594	498	513	546
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
-HIGHER NOx REDUCTION (tons/yr)	2374	2968	3957	5936	6728	2982	4500	3957	3957
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	771	740	705	661	649	799	670	689	734

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991
SOLID/ASH WASTE DISPOSAL ($/ton)	8.00	IAPCS, 1990

NOx CONTROL COSTS - COAL: DIFFERENTIAL FUEL COSTS NATURAL GAS REBURN - PC CYCLONE UNITS (Farzan/EERC, 1991) cdifffc| SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	120	150	200	300	340	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	25	35
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	25	15
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.73	0.73	0.73	0.73	0.73	0.55	0.83	0.73	0.73
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)	22	22	22	22	22	22	22	22	22
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	14496	18119	24159	36239	41071	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.110	0.131
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	-----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	-----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	27.48	25.13	22.40	19.05	18.12	22.40	22.40	22.40	22.40
-GENERAL FACILITIES (GF) 10% of PCC	2.75	2.51	2.24	1.90	1.81	2.24	2.24	2.24	2.24
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	2.75	2.51	2.24	1.90	1.81	2.24	2.24	2.24	2.24
-PROCESS CONTINGENCY (Proc) 20% of PCC	5.50	5.03	4.48	3.81	3.62	4.48	4.48	4.48	4.48
-PROJECT CONTING. (% of PCC+GF+EHOF+Proc) 30%	11.54	10.56	9.41	8.00	7.61	9.41	9.41	9.41	9.41
TOTAL PLANT COSTS (TPC) (1991$/kW) =	50	46	41	35	33	41	41	41	41
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	50	46	41	35	33	41	41	41	41
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-PREPRODUCTION COSTS 2% of TPC	1.00	0.91	0.82	0.69	0.66	0.82	0.82	0.82	0.82
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	51	47	42	35	34	42	42	42	42
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	0.999	0.914	0.815	0.693	0.659	0.815	0.815	0.815	0.815
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.093	0.083	0.071	0.056	0.052	0.071	0.071	0.071	0.071
FIXED O & M COSTS ($/kW-yr) =	0.73	0.66	0.58	0.48	0.45	0.44	0.66	0.58	0.58
VARIABLE O & M COSTS (mills/kW-hr) =	0.042	0.038	0.034	0.028	0.026	0.074	0.019	0.034	0.034

NOx CONTROL COSTS - COAL: DIFFERENTIAL FUEL COSTS NATURAL GAS REBURN - PC CYCLONE UNITS (Farzan/EERC, 1991) cdifffc| SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	120	150	200	300	340	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	-1019	-1273	-1698	-2547	-2887	-1279	-1931	-1698	-1698
-COAL (tons/yr)	-45384	-56730	-75640	-113460	-128588	-56989	-86002	-75640	-75640
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	1228185	1535232	2046975	3070463	3479858	1542242	2327383	2046975	2046975
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-SOLID/ASH WASTE DISPOSAL (mills/kW-hr)	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
FUEL COSTS									
-COAL (mills/kW-hr)	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	3.201	3.201	3.201	3.201	3.201	3.201	3.201	3.201	3.201
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.115	0.104	0.091	0.075	0.071	0.091	0.091	0.091	0.091
-VARIABLE O & M (mills/kW-Hr)	0.042	0.038	0.034	0.028	0.026	0.074	0.019	0.034	0.034
-CONSUMABLES (mills/kW-Hr)	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
-FUEL (mills/kW-Hr)	0.490	0.490	0.490	0.490	0.490	0.490	0.490	0.490	0.490
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	5.99	5.48	4.88	4.15	3.95	4.88	4.88	4.58	5.47
LEVELIZED BUSBAR COST (mills/kW-hr) =	1.41	1.31	1.20	1.07	1.03	1.49	1.10	1.16	1.30
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
-LOWER CONTROLLED NOx (lb/MMBtu)	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
-LOWER NOx REDUCTION (tons/yr)	3193	3992	5322	7983	9048	4010	6051	5322	5322
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	339	316	289	257	248	359	264	278	311
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
-HIGHER NOx REDUCTION (tons/yr)	2374	2968	3957	5936	6728	2982	4500	3957	3957
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	456	425	389	345	333	483	355	374	419

APPLICABLE UNIT PRICING	UNIT COST			
COAL ($/ton)	45.84	Electric Power Monthly, March 1991		
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991		
GAS ($/1000 ft^3)	2	Gas Facts, 1991		
AMMONIA ($/ton)	145.00	Robie, 1991		
UREA ($/ton)	220.00	BP Chemical, 1991		
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991		
CATALYST COST ($/ft^3)	660.00	Robie, 1991	1.752	$/MMBtu for Coal
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991	2.000	$/MMBtu for Gas
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991		
SOLID/ASH WASTE DISPOSAL ($/ton)	8.00	IAPCS, 1990	0.248	Differential Fuel Cost

NOx CONTROL COSTS - COAL: DIFFERENTIAL FUEL COSTS NATURAL GAS REBURN - PC CYCLONE UNITS (Farzan/EERC, 1991) cdifffc| SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	120	150	200	300	340	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	25	35
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	25	15
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.73	0.73	0.73	0.73	0.73	0.55	0.83	0.73	0.73
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)	22	22	22	22	22	22	22	22	22
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	14496	18119	24159	36239	41071	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.110	0.131
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	-----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	-----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	27.48	25.13	22.40	19.05	18.12	22.40	22.40	22.40	22.40
-GENERAL FACILITIES (GF) 10% of PCC	2.75	2.51	2.24	1.90	1.81	2.24	2.24	2.24	2.24
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	2.75	2.51	2.24	1.90	1.81	2.24	2.24	2.24	2.24
-PROCESS CONTINGENCY (Proc) 20% of PCC	5.50	5.03	4.48	3.81	3.62	4.48	4.48	4.48	4.48
-PROJECT CONTING. (% of PCC+GF+EHOF+Proc) 30%	11.54	10.56	9.41	8.00	7.61	9.41	9.41	9.41	9.41
TOTAL PLANT COSTS (TPC) (1991$/kW) =	50	46	41	35	33	41	41	41	41
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	50	46	41	35	33	41	41	41	41
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-PREPRODUCTION COSTS 2% of TPC	1.00	0.91	0.82	0.69	0.66	0.82	0.82	0.82	0.82
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	51	47	42	35	34	42	42	42	42
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	0.999	0.914	0.815	0.693	0.659	0.815	0.815	0.815	0.815
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.093	0.083	0.071	0.056	0.052	0.071	0.071	0.071	0.071
FIXED O & M COSTS ($/kW-yr) =	0.73	0.66	0.58	0.48	0.45	0.44	0.66	0.58	0.58
VARIABLE O & M COSTS (mills/kW-hr) =	0.042	0.038	0.034	0.028	0.026	0.074	0.019	0.034	0.034

NOx CONTROL COSTS - COAL: DIFFERENTIAL FUEL COSTS NATURAL GAS REBURN - PC CYCLONE UNITS (Farzan/EERC, 1991) cdifffc SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	120	150	200	300	340	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	-1019	-1273	-1698	-2547	-2887	-1279	-1931	-1698	-1698
-COAL (tons/yr)	-45384	-56730	-75640	-113460	-128588	-56989	-86002	-75640	-75640
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	1228185	1535232	2046975	3070463	3479858	1542242	2327383	2046975	2046975
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-SOLID/ASH WASTE DISPOSAL (mills/kW-hr)	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
FUEL COSTS									
-COAL (mills/kW-hr)	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	4.001	4.001	4.001	4.001	4.001	4.001	4.001	4.001	4.001
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.115	0.104	0.091	0.075	0.071	0.091	0.091	0.091	0.091
-VARIABLE O & M (mills/kW-Hr)	0.042	0.038	0.034	0.028	0.026	0.074	0.019	0.034	0.034
-CONSUMABLES (mills/kW-Hr)	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
-FUEL (mills/kW-Hr)	1.290	1.290	1.290	1.290	1.290	1.290	1.290	1.290	1.290
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	5.99	5.48	4.88	4.15	3.95	4.88	4.88	4.58	5.47
LEVELIZED BUSBAR COST (mills/kW-hr) =	2.21	2.12	2.00	1.87	1.83	2.30	1.90	1.96	2.10
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
-LOWER CONTROLLED NOx (lb/MMBtu)	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
-LOWER NOx REDUCTION (tons/yr)	3193	3992	5322	7983	9048	4010	6051	5322	5322
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	531	508	482	449	440	552	456	470	504
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
-HIGHER NOx REDUCTION (tons/yr)	2374	2968	3957	5936	6728	2982	4500	3957	3957
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	714	684	648	604	592	742	613	632	677

APPLICABLE UNIT PRICING	UNIT COST			
COAL ($/ton)	45.84	Electric Power Monthly, March 1991		
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991		
GAS ($/1000 ft^3)	2.5	Gas Facts, 1991		
AMMONIA ($/ton)	145.00	Robie, 1991		
UREA ($/ton)	220.00	BP Chemical, 1991		
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991		
CATALYST COST ($/ft^3)	660.00	Robie, 1991	1.752	$/MMBtu for Coal
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991	2.500	$/MMBtu for Gas
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991		
SOLID/ASH WASTE DISPOSAL ($/ton)	8.00	IAPCS, 1990	0.748	Differential Fuel Cost

NOx CONTROL COSTS - COAL: DIFFERENTIAL FUEL COSTS NATURAL GAS REBURN - PC CYCLONE UNITS (Farzan/EERC, 1991) cdifffc| SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	120	150	200	300	340	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	25	35
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	25	15
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.73	0.73	0.73	0.73	0.73	0.55	0.83	0.73	0.73
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)	22	22	22	22	22	22	22	22	22
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	14496	18119	24159	36239	41071	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.110	0.131
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	-----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	-----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	27.48	25.13	22.40	19.05	18.12	22.40	22.40	22.40	22.40
-GENERAL FACILITIES (GF) 10% of PCC	2.75	2.51	2.24	1.90	1.81	2.24	2.24	2.24	2.24
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	2.75	2.51	2.24	1.90	1.81	2.24	2.24	2.24	2.24
-PROCESS CONTINGENCY (Proc) 20% of PCC	5.50	5.03	4.48	3.81	3.62	4.48	4.48	4.48	4.48
-PROJECT CONTING. (% of PCC+GF+EHOF+Proc) 30%	11.54	10.56	9.41	8.00	7.61	9.41	9.41	9.41	9.41
TOTAL PLANT COSTS (TPC) (1991$/kW) =	50	46	41	35	33	41	41	41	41
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	50	46	41	35	33	41	41	41	41
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-PREPRODUCTION COSTS 2% of TPC	1.00	0.91	0.82	0.69	0.66	0.82	0.82	0.82	0.82
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	51	47	42	35	34	42	42	42	42
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	0.999	0.914	0.815	0.693	0.659	0.815	0.815	0.815	0.815
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.093	0.083	0.071	0.056	0.052	0.071	0.071	0.071	0.071
FIXED O & M COSTS ($/kW-yr) =	0.73	0.66	0.58	0.48	0.45	0.44	0.66	0.58	0.58
VARIABLE O & M COSTS (mills/kW-hr) =	0.042	0.038	0.034	0.028	0.026	0.074	0.019	0.034	0.034

NOx CONTROL COSTS - COAL: DIFFERENTIAL FUEL COSTS NATURAL GAS REBURN - PC CYCLONE UNITS (Farzan/EERC, 1991) cdifffc SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	120	150	200	300	340	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	-1019	-1273	-1698	-2547	-2887	-1279	-1931	-1698	-1698
-COAL (tons/yr)	-45384	-56730	-75640	-113460	-128588	-56989	-86002	-75640	-75640
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	1228185	1535232	2046975	3070463	3479858	1542242	2327383	2046975	2046975
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-SOLID/ASH WASTE DISPOSAL (mills/kW-hr)	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
FUEL COSTS									
-COAL (mills/kW-hr)	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	4.802	4.802	4.802	4.802	4.802	4.802	4.801	4.802	4.802
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.115	0.104	0.091	0.075	0.071	0.091	0.091	0.091	0.091
-VARIABLE O & M (mills/kW-Hr)	0.042	0.038	0.034	0.028	0.026	0.074	0.019	0.034	0.034
-CONSUMABLES (mills/kW-Hr)	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
-FUEL (mills/kW-Hr)	2.090	2.090	2.090	2.090	2.090	2.090	2.090	2.090	2.090
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	5.99	5.48	4.88	4.15	3.95	4.88	4.88	4.58	5.47
LEVELIZED BUSBAR COST (mills/kW-hr) =	3.01	2.92	2.80	2.67	2.63	3.10	2.70	2.76	2.90
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
-LOWER CONTROLLED NOx (lb/MMBtu)	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
-LOWER NOx REDUCTION (tons/yr)	3193	3992	5322	7983	9048	4010	6051	5322	5322
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	723	701	674	641	632	744	648	663	696
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
-HIGHER NOx REDUCTION (tons/yr)	2374	2968	3957	5936	6728	2982	4500	3957	3957
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	973	942	906	863	850	1000	872	891	936

APPLICABLE UNIT PRICING	UNIT COST			
COAL ($/ton)	45.84	Electric Power Monthly, March 1991		
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991		
GAS ($/1000 ft^3)	3	Gas Facts, 1991		
AMMONIA ($/ton)	145.00	Robie, 1991		
UREA ($/ton)	220.00	BP Chemical, 1991		
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991		
CATALYST COST ($/ft^3)	660.00	Robie, 1991	1.752	$/MMBtu for Coal
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991	3.000	$/MMBtu for Gas
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991		
SOLID/ASH WASTE DISPOSAL ($/ton)	8.00	IAPCS, 1990	1.248	Differential Fuel Cost

NOx CONTROL COSTS - COAL: DIFFERENTIAL FUEL COSTS NATURAL GAS REBURN - PC CYCLONE UNITS (Farzan/EERC, 1991) cdifffc| SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	120	150	200	300	340	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	25	35
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	25	15
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.73	0.73	0.73	0.73	0.73	0.55	0.83	0.73	0.73
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)	22	22	22	22	22	22	22	22	22
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	14496	18119	24159	36239	41071	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.110	0.131
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	-----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	-----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	27.48	25.13	22.40	19.05	18.12	22.40	22.40	22.40	22.40
-GENERAL FACILITIES (GF) 10% of PCC	2.75	2.51	2.24	1.90	1.81	2.24	2.24	2.24	2.24
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	2.75	2.51	2.24	1.90	1.81	2.24	2.24	2.24	2.24
-PROCESS CONTINGENCY (Proc) 20% of PCC	5.50	5.03	4.48	3.81	3.62	4.48	4.48	4.48	4.48
-PROJECT CONTING. (% of PCC+GF+EHOF+Proc) 30%	11.54	10.56	9.41	8.00	7.61	9.41	9.41	9.41	9.41
TOTAL PLANT COSTS (TPC) (1991$/kW) =	50	46	41	35	33	41	41	41	41
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	50	46	41	35	33	41	41	41	41
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-PREPRODUCTION COSTS 2% of TPC	1.00	0.91	0.82	0.69	0.66	0.82	0.82	0.82	0.82
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	51	47	42	35	34	42	42	42	42
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	0.999	0.914	0.815	0.693	0.659	0.815	0.815	0.815	0.815
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.093	0.083	0.071	0.056	0.052	0.071	0.071	0.071	0.071
FIXED O & M COSTS ($/kW-yr) =	0.73	0.66	0.58	0.48	0.45	0.44	0.66	0.58	0.58
VARIABLE O & M COSTS (mills/kW-hr) =	0.042	0.038	0.034	0.028	0.026	0.074	0.019	0.034	0.034

NOx CONTROL COSTS - COAL: DIFFERENTIAL FUEL COSTS NATURAL GAS REBURN - PC CYCLONE UNITS (Farzan/EERC, 1991) cdifffc| SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	120	150	200	300	340	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	-1019	-1273	-1698	-2547	-2887	-1279	-1931	-1698	-1698
-COAL (tons/yr)	-45384	-56730	-75640	-113460	-128588	-56989	-86002	-75640	-75640
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	1228185	1535232	2046975	3070463	3479858	1542242	2327383	2046975	2046975
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-SOLID/ASH WASTE DISPOSAL (mills/kW-hr)	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
FUEL COSTS									
-COAL (mills/kW-hr)	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	5.602	5.602	5.602	5.602	5.602	5.602	5.602	5.602	5.602
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.115	0.104	0.091	0.075	0.071	0.091	0.091	0.091	0.091
-VARIABLE O & M (mills/kW-Hr)	0.042	0.038	0.034	0.028	0.026	0.074	0.019	0.034	0.034
-CONSUMABLES (mills/kW-Hr)	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
-FUEL (mills/kW-Hr)	2.891	2.891	2.891	2.891	2.891	2.891	2.891	2.891	2.891
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	5.99	5.48	4.88	4.15	3.95	4.88	4.88	4.58	5.47
LEVELIZED BUSBAR COST (mills/kW-hr) =	3.81	3.72	3.60	3.47	3.43	3.90	3.50	3.56	3.70
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
-LOWER CONTROLLED NOx (lb/MMBtu)	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
-LOWER NOx REDUCTION (tons/yr)	3193	3992	5322	7983	9048	4010	6051	5322	5322
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	916	893	866	834	825	936	841	855	888
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
-HIGHER NOx REDUCTION (tons/yr)	2374	2968	3957	5936	6728	2982	4500	3957	3957
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1231	1201	1165	1121	1109	1259	1130	1150	1194

APPLICABLE UNIT PRICING	UNIT COST			
COAL ($/ton)	45.84	Electric Power Monthly, March 1991		
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991		
GAS ($/1000 ft^3)	3.5	Gas Facts, 1991		
AMMONIA ($/ton)	145.00	Robie, 1991		
UREA ($/ton)	220.00	BP Chemical, 1991		
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991		
CATALYST COST ($/ft^3)	660.00	Robie, 1991	1.752	$/MMBtu for Coal
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991	3.500	$/MMBtu for Gas
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991		
SOLID/ASH WASTE DISPOSAL ($/ton)	8.00	IAPCS, 1990	1.748	Differential Fuel Cost

NOx CONTROL COSTS - COAL: DIFFERENTIAL FUEL COSTS NATURAL GAS REBURN - PC CYCLONE UNITS (Farzan/EERC, 1991) cdifffc| SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	120	150	200	300	340	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	25	35
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	25	15
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.73	0.73	0.73	0.73	0.73	0.55	0.83	0.73	0.73
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)	22	22	22	22	22	22	22	22	22
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	14496	18119	24159	36239	41071	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.110	0.131
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	-----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	-----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	-----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	27.48	25.13	22.40	19.05	18.12	22.40	22.40	22.40	22.40
-GENERAL FACILITIES (GF) 10% of PCC	2.75	2.51	2.24	1.90	1.81	2.24	2.24	2.24	2.24
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	2.75	2.51	2.24	1.90	1.81	2.24	2.24	2.24	2.24
-PROCESS CONTINGENCY (Proc) 20% of PCC	5.50	5.03	4.48	3.81	3.62	4.48	4.48	4.48	4.48
-PROJECT CONTING. (% of PCC+GF+EHOF+Proc) 30%	11.54	10.56	9.41	8.00	7.61	9.41	9.41	9.41	9.41
TOTAL PLANT COSTS (TPC) (1991$/kW) =	50	46	41	35	33	41	41	41	41
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	50	46	41	35	33	41	41	41	41
-ROYALTY ALLOWANCE 0.0% of PCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-PREPRODUCTION COSTS 2% of TPC	1.00	0.91	0.82	0.69	0.66	0.82	0.82	0.82	0.82
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	51	47	42	35	34	42	42	42	42
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089	-0.089
-MAINTENANCE COSTS (MC) ($/kW-yr) 2% of TPC	0.999	0.914	0.815	0.693	0.659	0.815	0.815	0.815	0.815
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.093	0.083	0.071	0.056	0.052	0.071	0.071	0.071	0 071
FIXED O & M COSTS ($/kW-yr) =	0.73	0.66	0.58	0.48	0.45	0.44	0.66	0.58	0.58
VARIABLE O & M COSTS (mills/kW-hr) =	0.042	0.038	0.034	0.028	0.026	0.074	0.019	0.034	0.034

NOx CONTROL COSTS - COAL: DIFFERENTIAL FUEL COSTS NATURAL GAS REBURN - PC CYCLONE UNITS (Farzan/EERC, 1991) cdifffc SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	120	150	200	300	340	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	-1019	-1273	-1698	-2547	-2887	-1279	-1931	-1698	-1698
-COAL (tons/yr)	-45384	-56730	-75640	-113460	-128588	-56989	-86002	-75640	-75640
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	1228185	1535232	2046975	3070463	3479858	1542242	2327383	2046975	2046975
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066	-0.066
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-SOLID/ASH WASTE DISPOSAL (mills/kW-hr)	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108	-0.108
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
FUEL COSTS									
-COAL (mills/kW-hr)	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711	-2.711
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	6.402	6.402	6.402	6.402	6.402	6.402	6.402	6.402	6.402
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.115	0.104	0.091	0.075	0.071	0.091	0.091	0.091	0.091
-VARIABLE O & M (mills/kW-Hr)	0.042	0.038	0.034	0.028	0.026	0.074	0.019	0.034	0.034
-CONSUMABLES (mills/kW-Hr)	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174	-0.174
-FUEL (mills/kW-Hr)	3.691	3.691	3.691	3.691	3.691	3.691	3.691	3.691	3.691
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	5.99	5.48	4.88	4.15	3.95	4.88	4.88	4.58	5.47
LEVELIZED BUSBAR COST (mills/kW-hr) =	4.61	4.52	4.41	4.27	4.23	4.70	4.30	4.36	4.50
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
-LOWER CONTROLLED NOx (lb/MMBtu)	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
-LOWER NOx REDUCTION (tons/yr)	3193	3992	5322	7983	9048	4010	6051	5322	5322
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1108	1085	1059	1026	1017	1128	1033	1047	1081
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
-HIGHER NOx REDUCTION (tons/yr)	2374	2968	3957	5936	6728	2982	4500	3957	3957
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1490	1459	1424	1380	1368	1518	1389	1408	1453

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	4	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991
SOLID/ASH WASTE DISPOSAL ($/ton)	8.00	IAPCS, 1990

1.752 $/MMBtu for Coal
4.000 $/MMBtu for Gas
2.248 Differential Fuel Cost

NOx CONTROL COSTS - COAL BOILERS c9wsncru.wk1	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
UREA NOx-OUT (SNCR-UNCONTR.)-WALL-FIRED (Nalco/Hunt, 1992) Case 9 | SIZE (MW)	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	14.78	11.20	9.52	8.49	6.95	11.20	11.20	11.20	11.20
-GENERAL FACILITIES (GF) 10% of PCC	1.48	1.12	0.95	0.85	0.69	1.12	1.12	1.12	1.12
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	1.48	1.12	0.95	0.85	0.69	1.12	1.12	1.12	1.12
-PROCESS CONTINGENCY (Proc) 10% of PCC	1.48	1.12	0.95	0.85	0.69	1.12	1.12	1.12	1.12
-PROJECT CONTINGENCY (% of PCC) 30%	4.43	3.36	2.86	2.55	2.08	3.36	3.36	3.36	3.36
TOTAL PLANT COSTS (TPC) (1991$/kW) =	24	18	15	14	11	18	18	18	18
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	24	18	15	14	11	18	18	18	18
-ROYALTY ALLOWANCE	1.70	1.38	0.92	0.84	0.52	0.25	0.25	0.25	0.25
-PREPRODUCTION COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	25	19	16	14	12	18	18	18	18
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.081	0.040	0.027	0.020	0.012	0.066	0.032	0.040	0.040
-MAINTENANCE COSTS (MC) ($/kW-yr)	0.042	0.021	0.014	0.011	0.006	0.034	0.017	0.021	0.021
-ADMIN/SUPPORT LABOR ($/kW-yr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FIXED O & M COSTS ($/kW-yr) =	0.08	0.04	0.03	0.02	0.01	0.04	0.04	0.04	0.04
VARIABLE O & M COSTS (mills/kW-hr) =	0.008	0.004	0.003	0.002	0.001	0.017	0.001	0.004	0.004

NOx CONTROL COSTS - COAL BOILERS c9wsncru.wk1 UREA NOx-OUT (SNCR-UNCONTR.)-WALL-FIRED (Nalco/Hunt, 1992) Case 9 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	2823	5646	8469	11293	18633	3475	7123	5646	5646
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	232	464	697	929	1533	286	586	464	464
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	1.091	1.091	1.091	1.091	1.091	1.091	1.091	1.091	1.091
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.091	1.091	1.091	1.091	1.091	1.091	1.091	1.091	1.091
FUEL COSTS									
-COAL (mills/kW-hr)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.014	0.007	0.005	0.004	0.002	0.011	0.006	0.007	0 007
-VARIABLE O & M (mills/kW-Hr)	0.008	0.004	0.003	0.002	0.001	0.017	0.001	0.004	0.004
-CONSUMABLES (mills/kW-Hr)	1.091	1.091	1.091	1.091	1.091	1.091	1.091	1.091	1.091
-FUEL (mills/kW-Hr)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	2.98	2.27	1.90	1.69	1.37	2.13	2.13	1 93	2.96
LEVELIZED BUSBAR COST (mills/kW-hr) =	1.65	1.52	1.45	1.41	1.35	1.75	1.41	1.46	1.64
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
-LOWER CONTROLLED NOx (lb/MMBtu)	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
-LOWER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	689	632	604	588	563	728	589	608	683
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
-HIGHER NOx REDUCTION (tons/yr)	911	1823	2734	3645	6015	1122	2299	1823	1823
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1033	949	906	882	845	1092	883	911	1024

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS c10wsncr.wk1 UREA NOx-OUT (SNCR-CONTROLLED) - WALL (Nalco/Hunt, 1992) Case 10 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	14.78	11.20	9.52	8.49	6.95	11.20	11.20	11.20	11.20
-GENERAL FACILITIES (GF) 10% of PCC	1.48	1.12	0.95	0.85	0.69	1.12	1.12	1.12	1.12
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	1.48	1.12	0.95	0.85	0.69	1.12	1.12	1.12	1.12
-PROCESS CONTINGENCY (Proc) 10% of PCC	1.48	1.12	0.95	0.85	0.69	1.12	1.12	1.12	1.12
-PROJECT CONTINGENCY (% of PCC) 30%	4.43	3.36	2.86	2.55	2.08	3.36	3.36	3.36	3.36
TOTAL PLANT COSTS (TPC) (1991$/kW) =	24	18	15	14	11	18	18	18	18
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	24	18	15	14	11	18	18	18	18
-ROYALTY ALLOWANCE	1.70	1.38	0.92	0.84	0.52	0.25	0.25	0.25	0.25
-PREPRODUCTION COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	25	19	16	14	12	18	18	18	18
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.081	0.040	0.027	0.020	0.012	0.066	0.032	0.040	0.040
-MAINTENANCE COSTS (MC) ($/kW-yr)	0.042	0.021	0.014	0.011	0.006	0.034	0.017	0.021	0.021
-ADMIN/SUPPORT LABOR ($/kW-yr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FIXED O & M COSTS ($/kW-yr) =	0.08	0.04	0.03	0.02	0.01	0.04	0.04	0.04	0.04
VARIABLE O & M COSTS (mills/kW-hr) =	0.008	0.004	0.003	0.002	0.001	0.017	0.001	0.004	0.004

NOx CONTROL COSTS - COAL BOILERS c10wsncr.wk1 UREA NOx-OUT (SNCR-CONTROLLED) - WALL (Nalco/Hunt, 1992) Case 10 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	1783	3566	5349	7132	11768	2194	4499	3566	3566
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	232	464	697	929	1533	286	586	464	464
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689
FUEL COSTS									
-COAL (mills/kW-hr)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.014	0.007	0.005	0.004	0.002	0.011	0.006	0.007	0.007
-VARIABLE O & M (mills/kW-Hr)	0.008	0.004	0.003	0.002	0.001	0.017	0.001	0.004	0 004
-CONSUMABLES (mills/kW-Hr)	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689
-FUEL (mills/kW-Hr)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	2.98	2.27	1.90	1.69	1.37	2.13	2.13	1.93	2.96
LEVELIZED BUSBAR COST (mills/kW-hr) =	1.25	1.12	1.05	1.01	0.95	1.35	1.01	1.06	1.24
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
-LOWER NOx REDUCTION (tons/yr)	759	1519	2278	3038	5012	935	1916	1519	1519
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	939	837	786	758	713	1009	758	792	928
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-HIGHER NOx REDUCTION (tons/yr)	456	911	1367	1823	3007	561	1150	911	911
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1565	1395	1310	1263	1188	1681	1264	1321	1547

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS cl1tsncr.wk1 UREA NOx-OUT (SNCR-UNCONTR.)-TANGENTIAL (Nalco/Hunt, 1992) Case 11 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	18119	24159	36239	45298	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	3020	4027	6040	7550	4027	4027	4027	4027
UREA NSR (molar)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	14.78	12.57	11.20	9.52	8.71	11.20	11.20	11.20	11 20
-GENERAL FACILITIES (GF) 10% of PCC	1.48	1.26	1.12	0.95	0.87	1.12	1.12	1.12	1.12
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	1.48	1.26	1.12	0.95	0.87	1.12	1.12	1.12	1.12
-PROCESS CONTINGENCY (Proc) 10% of PCC	1.48	1.26	1.12	0.95	0.87	1.12	1.12	1.12	1.12
-PROJECT CONTINGENCY (% of PCC) 30%	4.43	3.77	3.36	2.86	2.61	3.36	3.36	3.36	3.36
TOTAL PLANT COSTS (TPC) (1991$/kW) =	24	20	18	15	14	18	18	18	18
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	24	20	18	15	14	18	18	18	18
-ROYALTY ALLOWANCE	1.70	1.83	1.38	1.12	0.91	0.25	0.25	0.25	0.25
-PREPRODUCTION COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	25	22	19	16	15	18	18	18	18
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.081	0.054	0.040	0.027	0.022	0.066	0 032	0.040	0.040
-MAINTENANCE COSTS (MC) ($/kW-yr)	0.042	0.028	0.021	0.014	0.011	0.034	0.017	0.021	0 021
-ADMIN/SUPPORT LABOR ($/kW-yr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FIXED O & M COSTS ($/kW-yr) =	0.08	0.05	0.04	0.03	0.02	0.04	0 04	0.04	0.04
VARIABLE O & M COSTS (mills/kW-hr) =	0 008	0.005	0.004	0.003	0.002	0.017	0 001	0.004	0.004

NOx CONTROL COSTS - COAL BOILERS cl1tsncr.wk1 UREA NOx-OUT (SNCR-UNCONTR.)-TANGENTIAL (Nalco/Hunt, 1992) Case 11 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	1783	2675	3566	5349	6686	2194	4499	3566	3566
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	232	348	464	697	871	286	586	464	464
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689
FUEL COSTS									
-COAL (mills/kW-hr)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.014	0.009	0.007	0.005	0.004	0.011	0.006	0.007	0.007
-VARIABLE O & M (mills/kW-Hr)	0.008	0.005	0.004	0.003	0.002	0.017	0.001	0.004	0.004
-CONSUMABLES (mills/kW-Hr)	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689	0.689
-FUEL (mills/kW-Hr)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	2.98	2.58	2.27	1.92	1.74	2.13	2.13	1.93	2.96
LEVELIZED BUSBAR COST (mills/kW-hr) =	1.25	1.17	1.12	1.05	1.02	1.35	1.01	1.06	1.24
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-LOWER NOx REDUCTION (tons/yr)	911	1367	1823	2734	3417	1122	2299	1823	1823
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	782	734	698	657	637	841	632	660	773
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
-HIGHER NOx REDUCTION (tons/yr)	608	911	1215	1823	2278	748	1533	1215	1215
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1173	1101	1046	986	956	1261	948	991	1160

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS cl2tsncr.wk1 UREA NOx-OUT (SNCR-CONTR.) - TANGENTIAL (Nalco/Hunt, 1992) Case 12 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	18119	24159	36239	45298	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	3020	4027	6040	7550	4027	4027	4027	4027
UREA NSR (molar)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	14.78	12.57	11.20	9.52	8.71	11.20	11.20	11.20	11.20
-GENERAL FACILITIES (GF) 10% of PCC	1.48	1.26	1.12	0.95	0.87	1.12	1.12	1.12	1.12
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	1.48	1.26	1.12	0.95	0.87	1.12	1.12	1.12	1.12
-PROCESS CONTINGENCY (Proc) 10% of PCC	1.48	1.26	1.12	0.95	0.87	1.12	1.12	1.12	1.12
-PROJECT CONTINGENCY (% of PCC) 30%	4.43	3.77	3.36	2.86	2.61	3.36	3.36	3.36	3.36
TOTAL PLANT COSTS (TPC) (1991$/kW) =	24	20	18	15	14	18	18	18	18
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	24	20	18	15	14	18	18	18	18
-ROYALTY ALLOWANCE	1.70	1.83	1.38	1.12	0.91	0.25	0.25	0.25	0.25
-PREPRODUCTION COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	25	22	19	16	15	18	18	18	18
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.081	0.054	0.040	0.027	0.022	0.066	0.032	0.040	0.040
-MAINTENANCE COSTS (MC) ($/kW-yr)	0.042	0.028	0.021	0.014	0.011	0.034	0.017	0.021	0.021
-ADMIN/SUPPORT LABOR ($/kW-yr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FIXED O & M COSTS ($/kW-yr) =	0.08	0.05	0.04	0.03	0.02	0.04	0.04	0.04	0.04
VARIABLE O & M COSTS (mills/kW-hr) =	0.008	0.005	0.004	0.003	0.002	0.017	0.001	0.004	0.004

NOx CONTROL COSTS - COAL BOILERS c12tsncr.wk1 UREA NOx-OUT (SNCR-CONTR.) - TANGENTIAL (Nalco/Hunt, 1992) Case 12 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	1337	2006	2675	4012	5015	1646	3374	2675	2675
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	232	348	464	697	871	286	586	464	464
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517
FUEL COSTS									
-COAL (mills/kW-hr)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.014	0.009	0.007	0.005	0.004	0.011	0.006	0.007	0.007
-VARIABLE O & M (mills/kW-Hr)	0.008	0.005	0.004	0.003	0.002	0.017	0.001	0.004	0.004
-CONSUMABLES (mills/kW-Hr)	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517
-FUEL (mills/kW-Hr)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	2.98	2.58	2.27	1.92	1.74	2.13	2.13	1.93	2.96
LEVELIZED BUSBAR COST (mills/kW-hr) =	1.08	1.00	0.94	0.88	0.85	1.17	0.84	0.88	1.07
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-LOWER CONTROLLED NOx (lb/MMBtu)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
-LOWER NOx REDUCTION (tons/yr)	608	911	1215	1823	2278	748	1533	1215	1215
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1012	939	885	825	794	1099	787	829	999
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
-HIGHER NOx REDUCTION (tons/yr)	304	456	608	911	1139	374	766	608	608
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	2024	1879	1770	1649	1588	2199	1573	1658	1997

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS c13wscru.wk1	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
SCR-UNCONTROLLED (COLD SIDE) - WALL									
(Robie, 1991) Case 13 | SIZE (MW)	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.49	1.26	1.13	0.92	1.49	1.49	1.49	1.49
-Ducting	29.80	22.59	19.20	17.12	14.01	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	4.55	3.87	3.45	2.82	4.55	4 55	4.55	4.55
-Structural	17.73	13.43	11.42	10.18	8.33	13.43	13.43	13.43	13.43
-Reagent Storage & Distribution	7.17	5.44	4.62	4.12	3.37	5.44	5.44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	33.47	28.46	25.36	20.76	33.47	33.47	33.47	33.47
-Control System	2.16	1.63	1.39	1.24	1.01	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	51.23	43.56	38.82	31.77	51.23	51.23	51.23	51.23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	134	114	101	83	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13 38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.67	0.57	0.51	0.42	0.67	0.67	0.67	0 67
-PREPRODUCTION COSTS 2% of TPC	4.94	3.75	3.19	2.84	2.32	3.75	3.75	3.75	3 75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	192	163	145	119	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.268	0.218	0.193	0.164	0.165	0.338	0 268	0.268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	7.494	6.372	5.679	4.649	7.494	7.494	7 494	7 494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	0.980	0.830	0.740	0.607	0.949	1.001	0.980	0.980
FIXED O & M COSTS ($/kW-yr) =	7.55	5.68	4.82	4.30	3.52	3.44	7 24	5 68	5 68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537

NOx CONTROL COSTS - COAL BOILERS c13wscru.wk1 SCR-UNCONTROLLED (COLD SIDE) - WALL (Robie, 1991) Case 13 SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	1068	2137	3205	4273	7051	1315	2695	2137	2137
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	7978	12739	17501	29879	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	682606	1023909	1365212	2252600	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.272	0.272	0.272	0.272	0.272	0.272	0.272	0.272	0.272
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.350	0.373	0.384	0.398	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.583	0.583	0.583	0.583	0.583	0.948	0.462	0.583	0.583
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.007	0.007	0.007	0.007	0.007	0.011	0.005	0.007	0.007
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.145	1.212	1.235	1.246	1.260	1.581	1.090	1.212	1.212
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	0.998	0.847	0.755	0.619	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537
-CONSUMABLES (mills/kW-Hr)	1.145	1.212	1.235	1.246	1.260	1.581	1.090	1.212	1.212
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	22.53	19.15	17.07	13.97	22.53	22.53	20.34	31.21
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.97	8.27	7.47	6.97	6.23	12.03	7.02	7.88	9.79
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
-LOWER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-LOWER NOx REDUCTION (tons/yr)	2430	4860	7291	9721	16039	2991	6132	4860	4860
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	2336	1937	1749	1633	1460	2819	1645	1847	2295
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
-HIGHER NOx REDUCTION (tons/yr)	2126	4253	6379	8506	14034	2617	5365	4253	4253
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	2669	2214	1999	1866	1668	3221	1880	2111	2622

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS c14wscrc.wk1	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
SCR-CONTROLLED (COLD SIDE) - WALL-FIRED									
(Robie, 1991) Case 14 | SIZE (MW)	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.49	1.26	1.13	0.92	1.49	1.49	1.49	1.49
-Ducting	29.80	22.59	19.20	17.12	14.01	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	4.55	3.87	3.45	2.82	4.55	4.55	4.55	4.55
-Structural	17.73	13.43	11.42	10.18	8.33	13.43	13 43	13.43	13.43
-Reagent Storage & Distribution	7.17	5.44	4.62	4.12	3.37	5.44	5 44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	33.47	28.46	25.36	20.76	33.47	33.47	33.47	33 47
-Control System	2.16	1.63	1.39	1.24	1.01	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	51.23	43.56	38.82	31.77	51.23	51.23	51.23	51.23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	134	114	101	83	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13 38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.67	0.57	0.51	0.42	0.67	0.67	0.67	0.67
-PREPRODUCTION COSTS 2% of TPC	4.94	3.75	3.19	2.84	2.32	3.75	3.75	3.75	3.75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	192	163	145	119	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.268	0.218	0.193	0.164	0.165	0.338	0 268	0.268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	7.494	6.372	5.679	4.649	7.494	7.494	7 494	7.494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	0.980	0.830	0.740	0.607	0.949	1.001	0.980	0 980
FIXED O & M COSTS ($/kW-yr) =	7.55	5.68	4.82	4.30	3.52	3.44	7.24	5 68	5 68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.537	0.456	0.406	0.333	1.474	0 221	0.537	0.537

NOx CONTROL COSTS - COAL BOILERS c14wscrc.wk1 SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) Case 14 SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1349	2024	2699	4453	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	7978	12739	17501	29879	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	682606	1023909	1365212	2252600	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.350	0.373	0.384	0.398	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.583	0.583	0.583	0.583	0.583	0.948	0.462	0.583	0.583
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.007	0.007	0.007	0.007	0.007	0.011	0.005	0.007	0.007
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.044	1.112	1.135	1.146	1.159	1.481	0.990	1.112	1.112
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	0.998	0.847	0.755	0.619	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537
-CONSUMABLES (mills/kW-Hr)	1.044	1.112	1.135	1.146	1.159	1.481	0.990	1.112	1.112
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	22.53	19.15	17.07	13.97	22.53	22.53	20.34	31.21
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.87	8.17	7.37	6.87	6.13	11.93	6.92	7.78	9.69
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1519	3038	4557	6075	10025	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3700	3062	2761	2575	2298	4473	2594	2918	3634
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4111	3402	3068	2862	2553	4969	2882	3243	4037

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS c15tscru.wk1	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
SCR-UNCONTROLLED (COLD SIDE)-TANGENTIAL (Robie, 1991) Case 15 | SIZE (MW)	100	150	200	300	375	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	18119	24159	36239	45298	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	3020	4027	6040	7550	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.67	1.49	1.26	1.16	1.49	1.49	1.49	1.49
-Ducting	29.80	25.34	22.59	19.20	17.56	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	5.11	4.55	3.87	3.54	4.55	4.55	4.55	4.55
-Structural	17.73	15.07	13.43	11.42	10.45	13.43	13.43	13.43	13.43
-Reagent Storage & Distribution	7.17	6.10	5.44	4.62	4.23	5.44	5.44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	37.55	33.47	28.46	26.03	33.47	33.47	33.47	33.47
-Control System	2.16	1.83	1.63	1.39	1.27	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	57.47	51.23	43.56	39.84	51.23	51.23	51.23	51.23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	150	134	114	104	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	15.01	13.38	11.38	10.41	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	15.01	13.38	11.38	10.41	13.38	13.38	13.38	13.38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	15.01	13.38	11.38	10.41	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	15.01	13.38	11.38	10.41	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	210	187	159	146	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	210	187	159	146	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.75	0.67	0.57	0.52	0.67	0.67	0.67	0 67
-PREPRODUCTION COSTS 2% of TPC	4.94	4.20	3.75	3.19	2.91	3.75	3.75	3.75	3.75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	215	192	163	149	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.318	0.268	0.218	0.198	0.165	0 338	0.268	0.268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	8.408	7.494	6.372	5.828	7.494	7.494	7.494	7 494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	1.104	0.980	0.830	0.759	0.949	1.001	0.980	0.980
FIXED O & M COSTS ($/kW-yr) =	7.55	6.39	5.68	4.82	4.41	3.44	7.24	5.68	5.68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.604	0.537	0.456	0.417	1.474	0.221	0.537	0 537

NOx CONTROL COSTS - COAL BOILERS c15tscru.wk1 SCR-UNCONTROLLED (COLD SIDE)-TANGENTIAL (Robie, 1991) Case 15 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1012	1349	2024	2530	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	5598	7978	12739	16310	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	511955	682606	1023909	1279886	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.328	0.350	0.373	0.382	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.583	0.583	0.583	0.583	0.583	0.948	0.462	0.583	0.583
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.007	0.007	0.007	0.007	0.007	0.011	0.005	0.007	0.007
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.044	1.090	1.112	1.135	1.144	1.481	0.990	1.112	1.112
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	1.122	0.998	0.847	0.775	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.604	0.537	0.456	0.417	1.474	0.221	0.537	0.537
-CONSUMABLES (mills/kW-Hr)	1.044	1.090	1.112	1.135	1.144	1.481	0.990	1.112	1.112
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	25.27	22.53	19.15	17.52	22.53	22.53	20.34	31.21
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.87	8.82	8.17	7.37	6.98	11.93	6.92	7.78	9.69
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1519	2278	3038	4557	5696	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3700	3306	3062	2761	2615	4473	2594	2918	3634
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	1367	2050	2734	4101	5126	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4111	3673	3402	3068	2906	4969	2882	3243	4037

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS c16tscrc.wk1	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
SCR-CONTROLLED (COLD SIDE) - TANGENTIAL									
(Robie, 1991) Case 16 | SIZE (MW)	100	150	200	300	375	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	18119	24159	36239	45298	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	3020	4027	6040	7550	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.67	1.49	1.26	1.16	1.49	1.49	1.49	1.49
-Ducting	29.80	25.34	22.59	19.20	17.56	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	5.11	4.55	3.87	3.54	4.55	4.55	4.55	4.55
-Structural	17.73	15.07	13.43	11.42	10.45	13.43	13.43	13.43	13.43
-Reagent Storage & Distribution	7.17	6.10	5.44	4.62	4.23	5.44	5.44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	37.55	33.47	28.46	26.03	33.47	33.47	33.47	33 47
-Control System	2.16	1.83	1.63	1.39	1.27	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	57.47	51.23	43.56	39.84	51.23	51.23	51.23	51.23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	150	134	114	104	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	15.01	13.38	11.38	10.41	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	15.01	13.38	11.38	10.41	13.38	13.38	13.38	13 38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	15.01	13.38	11.38	10.41	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	15.01	13.38	11.38	10.41	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	210	187	159	146	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	210	187	159	146	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.75	0.67	0.57	0.52	0.67	0 67	0.67	0 67
-PREPRODUCTION COSTS 2% of TPC	4.94	4.20	3.75	3.19	2.91	3.75	3.75	3.75	3 75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	215	192	163	149	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.318	0.268	0.218	0.198	0.165	0 338	0.268	0.268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	8.408	7.494	6.372	5.828	7 494	7 494	7 494	7.494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	1.104	0.980	0.830	0.759	0.949	1 001	0.980	0.980
FIXED O & M COSTS ($/kW-yr) =	7.55	6.39	5.68	4.82	4.41	3.44	7 24	5 68	5.68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.604	0.537	0.456	0.417	1.474	0 221	0.537	0 537

NOx CONTROL COSTS - COAL BOILERS c16tscrc.wk1 SCR-CONTROLLED (COLD SIDE) - TANGENTIAL (Robie, 1991) Case 16 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	506	759	1012	1518	1898	623	1277	1012	1012
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	5598	7978	12739	16310	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	511955	682606	1023909	1279886	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.129	0.129	0.129	0.129	0.129	0.129	0.129	0.129	0.129
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.328	0.350	0.373	0.382	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.583	0.583	0.583	0.583	0.583	0.948	0.462	0.583	0.583
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.007	0.007	0.007	0.007	0.007	0.011	0.005	0.007	0.007
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.001	1.047	1.069	1.092	1.101	1.438	0.947	1.069	1.069
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	1.122	0.998	0.847	0.775	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.604	0.537	0.456	0.417	1.474	0.221	0.537	0.537
-CONSUMABLES (mills/kW-Hr)	1.001	1.047	1.069	1.092	1.101	1.438	0.947	1.069	1.069
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	25.27	22.53	19.15	17.52	22.53	22.53	20.34	31.21
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.83	8.78	8.12	7.32	6.93	11.89	6.88	7.74	9.65
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-LOWER CONTROLLED NOx (lb/MMBtu)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
-LOWER NOx REDUCTION (tons/yr)	1215	1823	2430	3645	4557	1496	3066	2430	2430
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4605	4112	3807	3432	3249	5570	3223	3628	4522
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-HIGHER NOx REDUCTION (tons/yr)	1063	1595	2126	3190	3987	1309	2683	2126	2126
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	5262	4700	4351	3922	3713	6366	3683	4146	5168

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS c17wscrh.wk1 SCR-CONTROLLED (HOT SIDE) - WALL-FIRED (Robie, 1991) Case 17 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	18119	24159	36239	45298	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	3020	4027	6040	7550	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	17.72	15.07	13.43	11.42	10.44	13.43	13.43	13.43	13.43
-Fan Upgrade/Replace	6.60	5.61	5.00	4.25	3.89	5.00	5.00	5.00	5.00
-Structural	7.02	5.97	5.32	4.52	4.14	5.32	5.32	5.32	5.32
-Reagent Storage & Distribution	6.01	5.11	4.56	3.87	3.54	4.56	4.56	4.56	4.56
-DeNOx Reactor/Catalyst	78.13	66.43	59.21	50.34	46.05	59.21	59.21	59.21	59.21
-Control System and Additions	1.41	1.20	1.07	0.91	0.83	1.07	1.07	1.07	1.07
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	14.47	12.30	10.97	9.32	8.53	10.97	10.97	10.97	10 97
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	131	112	100	85	77	100	100	100	100
-GENERAL FACILITIES (GF) 10% of PCC	13.14	11.17	9.96	8.46	7.74	9.96	9.96	9.96	9 96
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	13.14	11.17	9.96	8.46	7.74	9.96	9.96	9.96	9 96
-PROCESS CONTINGENCY (Proc) 10% of PCC	13.14	11.17	9.96	8.46	7.74	9.96	9.96	9.96	9 96
-PROJECT CONTINGENCY (% of PCC) 15%	19.70	16.75	14.93	12.70	11.61	14.93	14.93	14.93	14.93
TOTAL PLANT COSTS (TPC) (1991$/kW) =	190	162	144	123	112	144	144	144	144
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	190	162	144	123	112	144	144	144	144
-ROYALTY ALLOWANCE 0.5% of PCC	0.66	0.56	0.50	0.42	0.39	0.50	0.50	0.50	0.50
-PREPRODUCTION COSTS 2% of TPC	3.81	3.24	2.89	2.45	2.25	2.89	2.89	2.89	2 89
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	195	166	148	126	115	148	148	148	148
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.318	0.268	0.218	0.198	0.165	0.338	0.268	0 268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	7.619	6.478	5.774	4.909	4.490	5.774	5.774	5.774	5 774
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.039	0.873	0.773	0.655	0.598	0.742	0.794	0.773	0 773
FIXED O & M COSTS ($/kW-yr) =	5.90	4.98	4.43	3.76	3.44	2.67	5.66	4.43	4.43
VARIABLE O & M COSTS (mills/kW-hr) =	0.558	0.471	0.419	0.355	0.325	1.144	0.173	0.419	0.419

NOx CONTROL COSTS - COAL BOILERS c17wscrh.wk1 SCR-CONTROLLED (HOT SIDE) - WALL-FIRED (Robie, 1991) Case 17 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1012	1349	2024	2530	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	5236	9109	12983	20731	26541	7990	16379	12983	12983
-COAL (tons/yr)	6271	9406	12541	18812	23515	7718	15821	12541	12541
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)									
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.460	0.533	0.570	0.607	0.622	0.570	0.570	0.570	0.570
-CATALYST (mills/kW-hr)	0.583	0.583	0.583	0.583	0.583	0.948	0.462	0.583	0.583
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.007	0.007	0.007	0.007	0.007	0.011	0.005	0.007	0.007
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.222	1.295	1.332	1.369	1.383	1.701	1.210	1.332	1.332
FUEL COSTS									
-COAL (mills/kW-hr)	0.505	0.505	0.505	0.505	0.505	0.505	0.505	0.505	0.505
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.036	0.875	0.778	0.660	0.604	0.763	0.788	0.778	0.778
-VARIABLE O & M (mills/kW-Hr)	0.558	0.471	0.419	0.355	0.325	1.144	0.173	0.419	0.419
-CONSUMABLES (mills/kW-Hr)	1.222	1.295	1.332	1.369	1.383	1.701	1.210	1.332	1.332
-FUEL (mills/kW-Hr)	0.505	0.505	0.505	0.505	0.505	0.505	0.505	0.505	0.505
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	22.90	19.47	17.35	14.75	13.49	17.35	17.35	15.67	24.04
LEVELIZED BUSBAR COST (mills/kW-hr) =	7.34	6.57	6.08	5.48	5.19	9.06	5.09	5.79	7.26
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-LOWER NOx REDUCTION (tons/yr)	1367	2050	2734	4101	5126	1682	3449	2734	2734
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3058	2735	2533	2283	2160	3776	2121	2410	3022
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
-HIGHER NOx REDUCTION (tons/yr)	1215	1823	2430	3645	4557	1496	3066	2430	2430
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3440	3077	2850	2568	2431	4248	2386	2711	3400

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - COAL BOILERS c18tscrh.wk1	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
SCR-CONTROLLED (HOT SIDE) - TANGENTIAL (Robie, 1991) Case 18 | SIZE (MW)	100	150	200	300	375	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	18119	24159	36239	45298	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	3020	4027	6040	7550	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	17.72	15.07	13.43	11.42	10.44	13.43	13.43	13.43	13.43
-Fan Upgrade/Replace	6.60	5.61	5.00	4.25	3.89	5.00	5.00	5.00	5.00
-Structural	7.02	5.97	5.32	4.52	4.14	5.32	5.32	5.32	5.32
-Reagent Storage & Distribution	6.01	5.11	4.56	3.87	3.54	4.56	4.56	4.56	4.56
-DeNOx Reactor/Catalyst	78.13	66.43	59.21	50.34	46.05	59.21	59.21	59.21	59.21
-Control System and Additions	1.41	1.20	1.07	0.91	0.83	1.07	1.07	1.07	1.07
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	14.47	12.30	10.97	9.32	8.53	10.97	10.97	10.97	10.97
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	131	112	100	85	77	100	100	100	100
-GENERAL FACILITIES (GF) 10% of PCC	13.14	11.17	9.96	8.46	7.74	9.96	9.96	9.96	9.96
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	13.14	11.17	9.96	8.46	7.74	9.96	9.96	9.96	9.96
-PROCESS CONTINGENCY (Proc) 10% of PCC	13.14	11.17	9.96	8.46	7.74	9.96	9.96	9.96	9.96
-PROJECT CONTINGENCY (% of PCC) 15%	19.70	16.75	14.93	12.70	11.61	14.93	14.93	14.93	14.93
TOTAL PLANT COSTS (TPC) (1991$/kW) =	190	162	144	123	112	144	144	144	144
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	190	162	144	123	112	144	144	144	144
-ROYALTY ALLOWANCE 0.5% of PCC	0.66	0.56	0.50	0.42	0.39	0.50	0.50	0.50	0.50
-PREPRODUCTION COSTS 2% of TPC	3.81	3.24	2.89	2.45	2.25	2.89	2.89	2.89	2.89
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	195	166	148	126	115	148	148	148	148
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.318	0.268	0.218	0.198	0.165	0.338	0.268	0.268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	7.619	6.478	5.774	4.909	4.490	5.774	5.774	5.774	5.774
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.039	0.873	0.773	0.655	0.598	0.742	0.794	0.773	0.773
FIXED O & M COSTS ($/kW-yr) =	5.90	4.98	4.43	3.76	3.44	2.67	5.66	4.43	4.43
VARIABLE O & M COSTS (mills/kW-hr) =	0.558	0.471	0.419	0.355	0.325	1.144	0.173	0.419	0.419

NOx CONTROL COSTS - COAL BOILERS c18tscrh.wk1 SCR-CONTROLLED (HOT SIDE) - TANGENTIAL (Robie, 1991) Case 18 SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	150	200	300	375	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	506	759	1012	1518	1898	623	1277	1012	1012
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	5236	9109	12983	20731	26541	7990	16379	12983	12983
-COAL (tons/yr)	6271	9406	12541	18812	23515	7718	15821	12541	12541
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)									
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.129	0.129	0.129	0.129	0.129	0.129	0.129	0.129	0.129
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.460	0.533	0.570	0.607	0.622	0.570	0.570	0.570	0.570
-CATALYST (mills/kW-hr)	0.583	0.583	0.583	0.583	0.583	0.948	0.462	0.583	0.583
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.007	0.007	0.007	0.007	0.007	0.011	0.005	0.007	0.007
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.179	1.252	1.289	1.326	1.340	1.658	1.167	1.289	1 289
FUEL COSTS									
-COAL (mills/kW-hr)	0.505	0.505	0.505	0.505	0.505	0.505	0.505	0.505	0.505
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.036	0.875	0.778	0.660	0.604	0.763	0.788	0.778	0.778
-VARIABLE O & M (mills/kW-Hr)	0.558	0.471	0.419	0.355	0.325	1.144	0.173	0.419	0.419
-CONSUMABLES (mills/kW-Hr)	1.179	1.252	1.289	1.326	1.340	1.658	1.167	1.289	1.289
-FUEL (mills/kW-Hr)	0.505	0.505	0.505	0.505	0.505	0.505	0.505	0.505	0.505
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	22.90	19.47	17.35	14.75	13.49	17.35	17.35	15.67	24 04
LEVELIZED BUSBAR COST (mills/kW-hr) =	7.30	6.52	6.04	5.44	5.14	9.02	5.05	5.74	7.21
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1063	1595	2126	3190	3987	1309	2683	2126	2126
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3909	3493	3234	2912	2755	4831	2704	3076	3863
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	911	1367	1823	2734	3417	1122	2299	1823	1823
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4560	4076	3773	3397	3214	5637	3154	3588	4507

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST COST SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST COST | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.49	1.26	1.13	0.92	1.49	1.49	1.49	1.49
-Ducting	29.80	22.59	19.20	17.12	14.01	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	4.55	3.87	3.45	2.82	4.55	4.55	4.55	4.55
-Structural	17.73	13.43	11.42	10.18	8.33	13.43	13.43	13.43	13.43
-Reagent Storage & Distribution	7.17	5.44	4.62	4.12	3.37	5.44	5.44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	33.47	28.46	25.36	20.76	33.47	33.47	33.47	33.47
-Control System	2.16	1.63	1.39	1.24	1.01	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	51.23	43.56	38.82	31.77	51.23	51.23	51.23	51.23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	134	114	101	83	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.67	0.57	0.51	0.42	0.67	0.67	0.67	0.67
-PREPRODUCTION COSTS 2% of TPC	4.94	3.75	3.19	2.84	2.32	3.75	3.75	3.75	3.75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	192	163	145	119	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.268	0.218	0.193	0.164	0.165	0 338	0.268	0.268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	7.494	6.372	5.679	4.649	7.494	7.494	7.494	7.494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	0.980	0.830	0.740	0.607	0.949	1.001	0.980	0.980
FIXED O & M COSTS ($/kW-yr) =	7.55	5.68	4.82	4.30	3.52	3.44	7.24	5.68	5.68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST COST SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST COST | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1349	2024	2699	4453	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	7978	12739	17501	29879	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	682606	1023909	1365212	2252600	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.350	0.373	0.384	0.398	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.265	0.265	0.265	0.265	0.265	0.431	0.210	0.265	0.265
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.007	0.007	0.007	0.007	0.007	0.011	0.005	0.007	0.007
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.726	0.794	0.817	0.828	0.841	0.964	0.738	0.794	0.794
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	0.998	0.847	0.755	0.619	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537
-CONSUMABLES (mills/kW-Hr)	0.726	0.794	0.817	0.828	0.841	0.964	0.738	0.794	0.794
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	22.53	19.15	17.07	13.97	22.53	22.53	20.34	31.21
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.55	7.85	7.05	6.55	5.81	11.41	6.67	7.47	9.37
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1519	3038	4557	6075	10025	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3580	2943	2642	2456	2179	4279	2500	2799	3514
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3978	3270	2936	2729	2421	4754	2777	3110	3905

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	300.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST COST SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST COST | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.49	1.26	1.13	0.92	1.49	1.49	1.49	1.49
-Ducting	29.80	22.59	19.20	17.12	14.01	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	4.55	3.87	3.45	2.82	4.55	4.55	4.55	4.55
-Structural	17.73	13.43	11.42	10.18	8.33	13.43	13 43	13.43	13.43
-Reagent Storage & Distribution	7.17	5.44	4.62	4.12	3.37	5.44	5.44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	33.47	28.46	25.36	20.76	33.47	33.47	33.47	33.47
-Control System	2.16	1.63	1.39	1.24	1.01	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	51.23	43.56	38.82	31.77	51.23	51.23	51.23	51.23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	134	114	101	83	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13 38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.67	0.57	0.51	0.42	0.67	0.67	0.67	0 67
-PREPRODUCTION COSTS 2% of TPC	4.94	3.75	3.19	2.84	2.32	3.75	3.75	3.75	3.75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	192	163	145	119	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.268	0.218	0.193	0.164	0 165	0.338	0.268	0 268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	7.494	6.372	5.679	4.649	7.494	7.494	7.494	7.494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	0.980	0.830	0.740	0.607	0.949	1.001	0.980	0.980
FIXED O & M COSTS ($/kW-yr) =	7.55	5.68	4.82	4.30	3.52	3.44	7.24	5.68	5.68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST COST SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST COST | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1349	2024	2699	4453	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	7978	12739	17501	29879	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	682606	1023909	1365212	2252600	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.350	0.373	0.384	0.398	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.354	0.354	0.354	0.354	0.354	0.575	0.280	0.354	0.354
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.007	0.007	0.007	0.007	0.007	0.011	0.005	0.007	0.007
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.815	0.882	0.905	0.916	0.930	1.108	0.808	0.882	0.882
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	0.998	0.847	0.755	0.619	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537
-CONSUMABLES (mills/kW-Hr)	0.815	0.882	0.905	0.916	0.930	1.108	0.808	0.882	0.882
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	22.53	19.15	17.07	13.97	22.53	22.53	20.34	31 21
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.64	7.94	7.14	6.64	5.90	11.56	6.74	7.55	9 46
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1519	3038	4557	6075	10025	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3614	2976	2675	2489	2212	4332	2526	2832	3548
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4015	3306	2973	2766	2457	4814	2806	3147	3942

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	400.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST COST SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST COST | SIZE (MW)	EFFECT OF CAPACITY 100	200	300	400	660	EFFECT OF C.F. 200	200	EFFECT OF AGE 200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.49	1.26	1.13	0.92	1.49	1.49	1.49	1.49
-Ducting	29.80	22.59	19.20	17.12	14.01	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	4.55	3.87	3.45	2.82	4.55	4.55	4.55	4 55
-Structural	17.73	13.43	11.42	10.18	8.33	13.43	13.43	13.43	13.43
-Reagent Storage & Distribution	7.17	5.44	4.62	4.12	3.37	5.44	5.44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	33.47	28.46	25.36	20.76	33.47	33.47	33.47	33.47
-Control System	2.16	1.63	1.39	1.24	1.01	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	51.23	43.56	38.82	31.77	51.23	51.23	51.23	51.23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	134	114	101	83	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13 38	13.38	13.38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.67	0.57	0.51	0.42	0.67	0.67	0.67	0.67
-PREPRODUCTION COSTS 2% of TPC	4.94	3.75	3.19	2.84	2.32	3.75	3.75	3.75	3 75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	192	163	145	119	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.268	0.218	0.193	0.164	0.165	0.338	0.268	0 268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	7.494	6.372	5.679	4.649	7.494	7 494	7.494	7.494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	0.980	0.830	0.740	0.607	0.949	1.001	0.980	0 980
FIXED O & M COSTS ($/kW-yr) =	7.55	5.68	4.82	4.30	3.52	3.44	7.24	5.68	5.68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0 537

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST COST SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST COST| SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1349	2024	2699	4453	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	7978	12739	17501	29879	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	682606	1023909	1365212	2252600	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.350	0.373	0.384	0.398	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.442	0.442	0.442	0.442	0.442	0.718	0.350	0.442	0.442
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.007	0.007	0.007	0.007	0.007	0.011	0.005	0.007	0.007
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.903	0.971	0.993	1.005	1.018	1.251	0.878	0.971	0.971
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	0.998	0.847	0.755	0.619	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537
-CONSUMABLES (mills/kW-Hr)	0.903	0.971	0.993	1.005	1.018	1.251	0.878	0.971	0.971
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	22.53	19.15	17.07	13.97	22.53	22.53	20.34	31.21
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.73	8.03	7.22	6.73	5.99	11.70	6.81	7.64	9.55
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1519	3038	4557	6075	10025	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3647	3009	2708	2522	2245	4386	2552	2865	3581
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4052	3343	3009	2803	2494	4874	2836	3184	3979

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	500.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST COST SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST COST | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.49	1.26	1.13	0.92	1.49	1.49	1.49	1.49
-Ducting	29.80	22.59	19.20	17.12	14.01	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	4.55	3.87	3.45	2.82	4.55	4.55	4.55	4.55
-Structural	17.73	13.43	11.42	10.18	8.33	13.43	13 43	13.43	13.43
-Reagent Storage & Distribution	7.17	5.44	4.62	4.12	3.37	5.44	5 44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	33.47	28.46	25.36	20.76	33.47	33.47	33.47	33.47
-Control System	2.16	1.63	1.39	1.24	1.01	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	51.23	43.56	38.82	31.77	51.23	51.23	51.23	51.23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	134	114	101	83	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.67	0.57	0.51	0.42	0.67	0.67	0.67	0.67
-PREPRODUCTION COSTS 2% of TPC	4.94	3.75	3.19	2.84	2.32	3.75	3.75	3.75	3.75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	192	163	145	119	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.268	0.218	0.193	0.164	0.165	0 338	0.268	0.268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	7.494	6.372	5.679	4 649	7.494	7.494	7 494	7 494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	0.980	0.830	0.740	0.607	0.949	1.001	0.980	0.980
FIXED O & M COSTS ($/kW-yr) =	7.55	5.68	4.82	4.30	3.52	3.44	7.24	5 68	5 68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0 537

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST COST SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST COST | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1349	2024	2699	4453	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	7978	12739	17501	29879	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	682606	1023909	1365212	2252600	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.350	0.373	0.384	0.398	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.530	0.530	0.530	0.530	0.530	0.862	0.420	0.530	0.530
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.007	0.007	0.007	0.007	0.007	0.011	0.005	0.007	0.007
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.991	1.059	1.082	1.093	1.106	1.395	0.948	1.059	1.059
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1 564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	0.998	0.847	0.755	0.619	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537
-CONSUMABLES (mills/kW-Hr)	0.991	1.059	1.082	1.093	1.106	1.395	0.948	1.059	1.059
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	22.53	19.15	17.07	13.97	22.53	22 53	20.34	31.21
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.82	8.11	7.31	6.82	6.08	11.84	6.88	7.73	9.64
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1519	3038	4557	6075	10025	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3680	3042	2742	2556	2278	4440	2578	2898	3614
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4089	3380	3046	2839	2531	4934	2865	3220	4015

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	600.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST COST SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST COST| SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.49	1.26	1.13	0.92	1.49	1.49	1.49	1.49
-Ducting	29.80	22.59	19.20	17.12	14.01	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	4.55	3.87	3.45	2.82	4.55	4.55	4.55	4.55
-Structural	17.73	13.43	11.42	10.18	8.33	13.43	13.43	13.43	13.43
-Reagent Storage & Distribution	7.17	5.44	4.62	4.12	3.37	5.44	5.44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	33.47	28.46	25.36	20.76	33.47	33.47	33.47	33 47
-Control System	2.16	1.63	1.39	1.24	1.01	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	51.23	43.56	38.82	31.77	51.23	51.23	51.23	51.23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	134	114	101	83	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.67	0.57	0.51	0.42	0.67	0.67	0.67	0.67
-PREPRODUCTION COSTS 2% of TPC	4.94	3.75	3.19	2.84	2.32	3.75	3.75	3.75	3.75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	192	163	145	119	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.268	0.218	0.193	0.164	0.165	0.338	0.268	0 268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	7.494	6.372	5.679	4.649	7.494	7.494	7.494	7.494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	0.980	0.830	0.740	0.607	0.949	1.001	0.980	0 980
FIXED O & M COSTS ($/kW-yr) =	7.55	5.68	4.82	4.30	3.52	3.44	7 24	5 68	5 68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST COST SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST COST | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1349	2024	2699	4453	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	7978	12739	17501	29879	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	682606	1023909	1365212	2252600	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.350	0.373	0.384	0.398	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.619	0.619	0.619	0.619	0.619	1.005	0.490	0.619	0.619
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.007	0.007	0.007	0.007	0.007	0.011	0.005	0.007	0.007
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.080	1.148	1.170	1.181	1.195	1.538	1.018	1.148	1.148
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	0.998	0.847	0.755	0.619	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0 537
-CONSUMABLES (mills/kW-Hr)	1.080	1.148	1.170	1.181	1.195	1.538	1.018	1.148	1.148
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1 564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	22.53	19.15	17.07	13.97	22.53	22.53	20.34	31 21
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.90	8.20	7.40	6.91	6.16	11.99	6.95	7.82	9.73
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1519	3038	4557	6075	10025	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3713	3075	2775	2589	2311	4494	2605	2932	3647
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4126	3417	3083	2876	2568	4993	2894	3257	4052

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	700.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST LIFE SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST LIFE | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F;14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	2	2	2	2	2	2	2	2	2
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.49	1.26	1.13	0.92	1.49	1.49	1.49	1.49
-Ducting	29.80	22.59	19.20	17.12	14.01	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	4.55	3.87	3.45	2.82	4.55	4.55	4.55	4.55
-Structural	17.73	13.43	11.42	10.18	8.33	13.43	13.43	13.43	13.43
-Reagent Storage & Distribution	7.17	5.44	4.62	4.12	3.37	5.44	5.44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	33.47	28.46	25.36	20.76	33.47	33.47	33.47	33.47
-Control System	2.16	1.63	1.39	1.24	1.01	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	51.23	43.56	38.82	31.77	51.23	51.23	51.23	51 23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	134	114	101	83	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.67	0.57	0.51	0.42	0.67	0.67	0.67	0 67
-PREPRODUCTION COSTS 2% of TPC	4.94	3.75	3.19	2.84	2.32	3.75	3.75	3.75	3.75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	192	163	145	119	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.268	0.218	0.193	0.164	0.165	0.338	0.268	0.268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	7.494	6.372	5.679	4.649	7.494	7.494	7.494	7 494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	0.980	0.830	0.740	0.607	0.949	1.001	0.980	0.980
FIXED O & M COSTS ($/kW-yr) =	7.55	5.68	4.82	4.30	3.52	3.44	7 24	5 68	5 68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST LIFE SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST LIFE | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1349	2024	2699	4453	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	7978	12739	17501	29879	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	682606	1023909	1365212	2252600	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.350	0.373	0.384	0.398	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	1.195	1.195	1.195	1.195	1.195	1.942	0.947	1.195	1.195
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.014	0.014	0.014	0.014	0.014	0.022	0.011	0.014	0.014
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.663	1.731	1.754	1.765	1.778	2.487	1.480	1.731	1.731
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	0.998	0.847	0.755	0.619	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537
-CONSUMABLES (mills/kW-Hr)	1.663	1.731	1.754	1.765	1.778	2.487	1.480	1.731	1.731
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	22.53	19.15	17.07	13.97	22.53	22.53	20.34	31.21
LEVELIZED BUSBAR COST (mills/kW-hr) =	10.49	8.79	7.99	7.49	6.75	12.94	7.41	8.40	10.31
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1519	3038	4557	6075	10025	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3932	3294	2993	2807	2530	4850	2778	3150	3866
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4369	3660	3326	3119	2811	5388	3087	3500	4295

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST LIFE SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST LIFE | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	3	3	3	3	3	3	3	3	3
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0 163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.49	1.26	1.13	0.92	1.49	1.49	1.49	1.49
-Ducting	29.80	22.59	19.20	17.12	14.01	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	4.55	3.87	3.45	2.82	4 55	4.55	4.55	4.55
-Structural	17.73	13.43	11.42	10.18	8.33	13.43	13.43	13.43	13.43
-Reagent Storage & Distribution	7.17	5.44	4.62	4.12	3.37	5.44	5.44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	33.47	28.46	25.36	20.76	33.47	33.47	33.47	33.47
-Control System	2.16	1.63	1.39	1.24	1.01	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	51.23	43.56	38.82	31.77	51.23	51.23	51.23	51 23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	134	114	101	83	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.67	0.57	0.51	0.42	0.67	0.67	0.67	0 67
-PREPRODUCTION COSTS 2% of TPC	4.94	3.75	3.19	2.84	2.32	3.75	3.75	3.75	3.75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	192	163	145	119	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.268	0.218	0.193	0.164	0.165	0.338	0.268	0.268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	7.494	6.372	5.679	4.649	7 494	7.494	7.494	7 494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	0.980	0.830	0.740	0.607	0.949	1 001	0.980	0.980
FIXED O & M COSTS ($/kW-yr) =	7.55	5.68	4.82	4 30	3.52	3.44	7 24	5.68	5.68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST LIFE SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST LIFE| SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1349	2024	2699	4453	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	7978	12739	17501	29879	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	682606	1023909	1365212	2252600	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.350	0.373	0.384	0.398	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.787	0.787	0.787	0.787	0.787	1.279	0.624	0.787	0.787
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.009	0.009	0.009	0.009	0.009	0.015	0.007	0.009	0.009
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.251	1.318	1.341	1.352	1.366	1.816	1.153	1.318	1.318
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	0.998	0.847	0.755	0.619	0.983	1.008	0.998	0 998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537
-CONSUMABLES (mills/kW-Hr)	1.251	1.318	1.341	1.352	1.366	1.816	1.153	1.318	1.318
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	22.53	19.15	17.07	13.97	22.53	22.53	20.34	31.21
LEVELIZED BUSBAR COST (mills/kW-hr) =	10.08	8.37	7.57	7.08	6.34	12.27	7.08	7.99	9.90
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1519	3038	4557	6075	10025	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3777	3139	2839	2653	2375	4598	2655	2996	3711
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4197	3488	3154	2947	2639	5109	2950	3328	4123

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST LIFE SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST LIFE | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.49	1.26	1.13	0.92	1.49	1.49	1.49	1.49
-Ducting	29.80	22.59	19.20	17.12	14.01	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	4.55	3.87	3.45	2.82	4.55	4.55	4.55	4 55
-Structural	17.73	13.43	11.42	10.18	8.33	13.43	13.43	13.43	13.43
-Reagent Storage & Distribution	7.17	5.44	4.62	4.12	3.37	5.44	5.44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	33.47	28.46	25.36	20.76	33.47	33.47	33.47	33.47
-Control System	2.16	1.63	1.39	1.24	1.01	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	51.23	43.56	38.82	31.77	51.23	51.23	51.23	51.23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	134	114	101	83	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.67	0.57	0.51	0.42	0.67	0.67	0.67	0.67
-PREPRODUCTION COSTS 2% of TPC	4.94	3.75	3.19	2.84	2.32	3.75	3.75	3.75	3.75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	192	163	145	119	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.268	0.218	0.193	0.164	0.165	0.338	0 268	0 268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	7.494	6.372	5.679	4.649	7 494	7.494	7.494	7 494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	0.980	0.830	0.740	0.607	0.949	1.001	0.980	0 980
FIXED O & M COSTS ($/kW-yr) =	7.55	5.68	4.82	4.30	3.52	3.44	7 24	5.68	5.68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0 537

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST LIFE SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST LIFE| SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1349	2024	2699	4453	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	7978	12739	17501	29879	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	682606	1023909	1365212	2252600	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.350	0.373	0.384	0.398	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.583	0.583	0.583	0.583	0.583	0.948	0.462	0.583	0.583
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.007	0.007	0.007	0.007	0.007	0.011	0.005	0.007	0.007
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.044	1.112	1.135	1.146	1.159	1.481	0.990	1.112	1.112
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	0.998	0.847	0.755	0.619	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537
-CONSUMABLES (mills/kW-Hr)	1.044	1.112	1.135	1.146	1.159	1.481	0.990	1.112	1.112
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	22.53	19.15	17.07	13.97	22.53	22.53	20.34	31 21
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.87	8.17	7.37	6.87	6.13	11.93	6.92	7.78	9.69
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1519	3038	4557	6075	10025	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3700	3062	2761	2575	2298	4473	2594	2918	3634
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4111	3402	3068	2862	2553	4969	2882	3243	4037

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST LIFE	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
SCR-CONTROLLED (COLD SIDE) - WALL-FIRED									
(Robie, 1991) VARY CATALYST LIFE | SIZE (MW)	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	5	5	5	5	5	5	5	5	5
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.49	1.26	1.13	0.92	1.49	1.49	1.49	1.49
-Ducting	29.80	22.59	19.20	17.12	14.01	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	4.55	3.87	3.45	2.82	4.55	4.55	4.55	4.55
-Structural	17.73	13.43	11.42	10.18	8.33	13.43	13.43	13.43	13.43
-Reagent Storage & Distribution	7.17	5.44	4.62	4.12	3.37	5.44	5.44	5.44	5.44
-DeNOx Reactor/Catalyst	44.16	33.47	28.46	25.36	20.76	33.47	33.47	33.47	33.47
-Control System	2.16	1.63	1.39	1.24	1.01	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	51.23	43.56	38.82	31.77	51.23	51.23	51.23	51.23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	134	114	101	83	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.67	0.57	0.51	0.42	0.67	0.67	0.67	0.67
-PREPRODUCTION COSTS 2% of TPC	4.94	3.75	3.19	2.84	2.32	3.75	3.75	3.75	3 75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	192	163	145	119	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.268	0.218	0.193	0.164	0.165	0.338	0.268	0 268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	7.494	6.372	5.679	4.649	7.494	7.494	7.494	7 494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	0.980	0.830	0.740	0.607	0.949	1.001	0.980	0.980
FIXED O & M COSTS ($/kW-yr) =	7.55	5.68	4.82	4.30	3.52	3.44	7.24	5.68	5 68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST LIFE SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST LIFE | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1349	2024	2699	4453	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	7978	12739	17501	29879	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	682606	1023909	1365212	2252600	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.350	0.373	0.384	0.398	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.461	0.461	0.461	0.461	0.461	0.749	0.366	0.461	0.461
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.005	0.005	0.005	0.005	0.005	0.009	0.004	0.005	0.005
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.921	0.988	1.011	1.022	1.036	1.280	0.892	0.988	0.988
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	0.998	0.847	0.755	0.619	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0.537
-CONSUMABLES (mills/kW-Hr)	0.921	0.988	1.011	1.022	1.036	1.280	0.892	0.988	0.988
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	22.53	19.15	17.07	13.97	22.53	22.53	20.34	31 21
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.75	8.04	7.24	6.75	6.01	11.73	6.82	7.66	9.57
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1519	3038	4557	6075	10025	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3653	3016	2715	2529	2251	4397	2557	2872	3587
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4059	3351	3017	2810	2502	4886	2841	3191	3986

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST LIFE SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST LIFE | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	30	30	30	30	30	30	30	20	40
BOILER BOOK LIFE (Years)	20	20	20	20	20	20	20	30	10
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.65	0.65	0.65	0.65	0.65	0.40	0.82	0.65	0.65
COAL HHV (Btu/lb)	13080	13080	13080	13080	13080	13080	13080	13080	13080
NATURAL GAS HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OIL FRACTION	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	12080	24159	36239	48318	79725	24159	24159	24159	24159
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	6	6	6	6	6	6	6	6	6
CATALYST VOLUME (ft^3)	2013	4027	6040	8053	13288	4027	4027	4027	4027
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.117	0.117	0.117	0.117	0.117	0.117	0.117	0.106	0.163
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	1.96	1.49	1.26	1.13	0.92	1.49	1.49	1.49	1.49
-Ducting	29.80	22.59	19.20	17.12	14.01	22.59	22.59	22.59	22.59
-Fan Upgrade/Replace	6.01	4.55	3.87	3.45	2.82	4.55	4.55	4.55	4.55
-Structural	17.73	13.43	11.42	10.18	8.33	13.43	13.43	13.43	13.43
-Reagent Storage & Distribution	7.17	5.44	4.62	4.12	3.37	5.44	5.44	5.44	5 44
-DeNOx Reactor/Catalyst	44.16	33.47	28.46	25.36	20.76	33.47	33.47	33.47	33.47
-Control System	2.16	1.63	1.39	1.24	1.01	1.63	1.63	1.63	1.63
-Flue Gas Heat Exchanger	67.59	51.23	43.56	38.82	31.77	51.23	51.23	51.23	51.23
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	177	134	114	101	83	134	134	134	134
-GENERAL FACILITIES (GF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROCESS CONTINGENCY (Proc) 10% of PCC	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
-PROJECT CONTINGENCY (% of PCC) 10%	17.66	13.38	11.38	10.14	8.30	13.38	13.38	13.38	13.38
TOTAL PLANT COSTS (TPC) (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	247	187	159	142	116	187	187	187	187
-ROYALTY ALLOWANCE 0.5% of PCC	0.88	0.67	0.57	0.51	0.42	0.67	0.67	0.67	0 67
-PREPRODUCTION COSTS 2% of TPC	4.94	3.75	3.19	2.84	2.32	3.75	3.75	3.75	3.75
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	253	192	163	145	119	192	192	192	192
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.417	0.268	0.218	0.193	0.164	0.165	0.338	0.268	0.268
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	9.889	7.494	6.372	5.679	4.649	7.494	7.494	7.494	7 494
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	1.312	0.980	0.830	0.740	0.607	0.949	1.001	0.980	0.980
FIXED O & M COSTS ($/kW-yr) =	7.55	5.68	4.82	4.30	3.52	3.44	7 24	5.68	5 68
VARIABLE O & M COSTS (mills/kW-hr) =	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0 537	0 537

NOx CONTROL COSTS-COAL BOILERS : VARY CATALYST LIFE SCR-CONTROLLED (COLD SIDE) - WALL-FIRED (Robie, 1991) VARY CATALYST LIFE | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	300	400	660	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	675	1349	2024	2699	4453	830	1702	1349	1349
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3217	7978	12739	17501	29879	4910	10065	7978	7978
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)									
-GAS (1000 ft^3/yr)	341303	682606	1023909	1365212	2252600	420065	861134	682606	682606
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172	0.172
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.283	0.350	0.373	0.384	0.398	0.350	0.350	0.350	0.350
-CATALYST (mills/kW-hr)	0.380	0.380	0.380	0.380	0.380	0.617	0.301	0.380	0.380
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.004	0.004	0.004	0.004	0.004	0.007	0.003	0.004	0.004
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.838	0.906	0.929	0.940	0.953	1.146	0.826	0.906	0.906
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)									
-GAS (mills/kW-hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	1.326	0.998	0.847	0.755	0.619	0.983	1.008	0.998	0.998
-VARIABLE O & M (mills/kW-Hr)	0.714	0.537	0.456	0.406	0.333	1.474	0.221	0.537	0 537
-CONSUMABLES (mills/kW-Hr)	0.838	0.906	0.929	0.940	0.953	1.146	0.826	0.906	0.906
-FUEL (mills/kW-Hr)	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564	1.564
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	29.72	22.53	19.15	17.07	13.97	22.53	22.53	20.34	31.21
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.66	7.96	7.16	6.66	5.92	11.60	6.76	7.58	9.49
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	1519	3038	4557	6075	10025	1869	3832	3038	3038
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3622	2985	2684	2498	2221	4347	2533	2841	3556
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	1367	2734	4101	5468	9022	1682	3449	2734	2734
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4025	3316	2982	2776	2467	4830	2814	3157	3952

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

APPENDIX G

NO_x CONTROL COSTS

OIL-/GAS-FIRED BOILERS

The enclosed spreadsheets include cost estimates for the following cases:

1. Burners out of service (BOOS) for wall-fired boilers
2. Burners out of service (BOOS) for tangential boilers
3. Flue gas recirculation (FGR) for wall-fired boilers
4. Flue gas recirculation (FGR) for tangential boilers
5. Low-NO_x burners (LNB) for wall-fired boilers
6. Low-NO_x burners (LNB) for tangential boilers
7. Burners out of service (BOOS) and flue gas recirculation (FGR) for wall-fired boilers
8. Burners out of service (BOOS) and flue gas recirculation (FGR) for tangential boilers
9. Low-NO_x burners (LNB), flue gas recirculation (FGR), and overfire air (OFA) for wall-fired boilers
10. Low-NO_x burners (LNB), flue gas recirculation (FGR), and overfire air (OFA) for tangential boilers
11. Selective noncatalytic reduction (SNCR) for wall-fired boilers (uncontrolled)
12. Selective noncatalytic reduction (SNCR) for tangential boilers (uncontrolled)
13. Selective noncatalytic reduction (SNCR) for wall-fired boilers (with combustion controls)
14. Selective noncatalytic reduction (SNCR) for tangential boilers (with combustion controls)
15. Selective catalytic reduction (SCR) for wall-fired boilers (uncontrolled)
16. Selective catalytic reduction (SCR) for tangential boilers (uncontrolled)
17. Selective catalytic reduction (SCR) for wall-fired boilers (controlled)
18. Selective catalytic reduction (SCR) for tangential boilers (with combustion controls)

Uncontrolled NO_x is taken as the average of pre- and post-NSPS current baseline emission levels (see Table 3-3). For wall-fired retrofit cost cases, the average emission levels for wall- and opposed-fired boilers are used. For combustion-controlled NO_x emission levels, the average of the range provided in Table 4-7 for both pre- and post-NSPS boilers is used as a representative control NO_x target. For FGT controls, the average controlled level is taken from Table 4-10.

NOx CONTROL COSTS - GAS/OIL BOILERS glwboos.wk1	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
BOOS - WALL-FIRED UNITS									
(Mormile, 1987) Case 1 | SIZE (MW)	100	200	400	600	850	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	99505	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	0.48	0.36	0.27	0.23	0.20	0.36	0.36	0.36	0.36
-GENERAL FACILITIES (GF) 10% of PCC	0.05	0.04	0.03	0.02	0.02	0.04	0.04	0.04	0.04
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	0.05	0.04	0.03	0.02	0.02	0.04	0.04	0.04	0.04
-PROCESS CONTINGENCY (Proc) 10% of PCC	0.05	0.04	0.03	0.02	0.02	0.04	0.04	0.04	0.04
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	0.17	0.13	0.10	0.08	0.07	0.13	0.13	0.13	0.13
TOTAL PLANT COSTS (TPC) (1991$/kW) =	0.8	0.6	0.5	0.4	0.3	0.6	0.6	0.6	0.6
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	0.8	0.6	0.5	0.4	0.3	0.6	0.6	0.6	0.6
-ROYALTY ALLOWANCE 0.0% of PCC	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-PREPRODUCTION COSTS 2% of TPC	0.016	0.012	0.009	0.008	0.007	0.012	0.012	0.012	0.012
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	0.81	0.61	0.47	0.40	0.34	0.61	0.61	0 61	0.61
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.095	0.041	0.268	0.165	0 165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	0.032	0.024	0.018	0.016	0.014	0.024	0.024	0.024	0.024
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.081	0.052	0.038	0.033	0.030	0.015	0.083	0.052	0 052
FIXED O & M COSTS ($/kW-yr) =	0.148	0.097	0.070	0.061	0.055	0.008	0 244	0.097	0.097
VARIABLE O & M COSTS (mills/kW-hr) =	0.063	0.041	0.030	0.026	0.024	0.083	0 023	0 041	0 041

NOx CONTROL COSTS - GAS/OIL BOILERS glwboos.wk1 BOOS - WALL-FIRED UNITS (Mormile, 1987) Case 1 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	1192	2384	4769	7153	10134	596	3875	2384	2384
-GAS (1000 ft^3/yr)	3879	7758	15517	23275	32973	1940	12607	7758	7758
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078
-GAS (mills/kW-hr)	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.042	0.028	0.020	0.017	0.016	0.009	0.043	0.028	0.028
-VARIABLE O & M (mills/kW-Hr)	0.063	0.041	0.030	0.026	0.024	0.083	0.023	0.041	0.041
-CONSUMABLES (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-FUEL (mills/kW-Hr)	0.107	0.107	0.107	0.107	0.107	0.107	0.107	0.107	0.107
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	0.08	0.06	0.05	0.04	0.04	0.06	0.06	0.06	0.07
LEVELIZED BUSBAR COST (mills/kW-hr) =	0.24	0.19	0.17	0.16	0.16	0.27	0.18	0 19	0.20
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-LOWER CONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-LOWER NOx REDUCTION (tons/yr)	280	561	1122	1682	2383	140	911	561	561
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	295	242	213	202	195	339	230	242	245
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
-HIGHER NOx REDUCTION (tons/yr)	187	374	748	1122	1589	93	608	374	374
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	442	363	319	303	293	509	344	362	368

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g2tboos.wk1 BOOS - TANGENTIAL-FIRED UNITS (Mormile, 1987) Case 2 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	105358	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	0.48	0.36	0.27	0.23	0.20	0.36	0.36	0.36	0.36
-GENERAL FACILITIES (GF) 10% of PCC	0.05	0.04	0.03	0.02	0.02	0.04	0.04	0.04	0.04
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	0.05	0.04	0.03	0.02	0.02	0.04	0.04	0.04	0.04
-PROCESS CONTINGENCY (Proc) 10% of PCC	0.05	0.04	0.03	0.02	0.02	0.04	0.04	0.04	0.04
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	0.17	0.13	0.10	0.08	0.07	0.13	0.13	0.13	0.13
TOTAL PLANT COSTS (TPC) (1991$/kW) =	0.8	0.6	0.5	0.4	0.3	0.6	0.6	0.6	0.6
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	0.8	0.6	0.5	0.4	0.3	0.6	0.6	0.6	0.6
-ROYALTY ALLOWANCE 0.0% of PCC	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-PREPRODUCTION COSTS 2% of TPC	0.016	0.012	0.009	0.008	0.007	0.012	0.012	0.012	0.012
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	0.81	0.61	0.47	0.40	0.34	0.61	0.61	0.61	0.61
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.094	0.041	0.268	0.165	0.165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	0.032	0.024	0.018	0.016	0.013	0.024	0.024	0.024	0.024
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.081	0.052	0.038	0.033	0.030	0.015	0.083	0.052	0.052
FIXED O & M COSTS ($/kW-yr) =	0.148	0.097	0.070	0.061	0.055	0.008	0.244	0.097	0.097
VARIABLE O & M COSTS (mills/kW-hr) =	0.063	0.041	0.030	0.026	0.023	0.083	0.023	0.041	0.041

NOx CONTROL COSTS - GAS/OIL BOILERS g2tboos.wk1 BOOS - TANGENTIAL-FIRED UNITS (Mormile, 1987) Case 2 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	1192	2384	4769	7153	10730	596	3875	2384	2384
-GAS (1000 ft^3/yr)	3879	7758	15517	23275	34912	1940	12607	7758	7758
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078
-GAS (mills/kW-hr)	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0 029
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.042	0.028	0.020	0.017	0.016	0.009	0.043	0.028	0.028
-VARIABLE O & M (mills/kW-Hr)	0.063	0.041	0.030	0.026	0.023	0.083	0.023	0.041	0.041
-CONSUMABLES (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-FUEL (mills/kW-Hr)	0.107	0.107	0.107	0.107	0.107	0.107	0.107	0.107	0.107
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	0.08	0.06	0.05	0.04	0.03	0.06	0.06	0.06	0.07
LEVELIZED BUSBAR COST (mills/kW-hr) =	0.24	0.19	0.17	0.16	0.16	0.27	0.18	0.19	0.20
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-LOWER CONTROLLED NOx (lb/MMBtu)	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
-LOWER NOx REDUCTION (tons/yr)	187	374	748	1122	1682	93	608	374	374
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	442	363	319	303	292	509	344	362	368
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
-HIGHER NOx REDUCTION (tons/yr)	93	187	374	561	841	47	304	187	187
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	884	726	639	607	583	1017	689	725	735

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g3wfgr.wk1 FGR - WALL-FIRED UNITS (Mormile, 1987) Case 3 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	99505	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	7.76	5.88	4.46	3.79	3.30	5.88	5.88	5.88	5.88
-GENERAL FACILITIES (GF) 10% of PCC	0.78	0.59	0.45	0.38	0.33	0.59	0.59	0.59	0.59
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	0.78	0.59	0.45	0.38	0.33	0.59	0.59	0.59	0.59
-PROCESS CONTINGENCY (Proc) 10% of PCC	0.78	0.59	0.45	0.38	0.33	0.59	0.59	0.59	0.59
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	2.79	2.12	1.60	1.36	1.19	2.12	2.12	2.12	2.12
TOTAL PLANT COSTS (TPC) (1991$/kW) =	12.9	9.8	7.4	6.3	5.5	9.8	9.8	9.8	9.8
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	12.9	9.8	7.4	6.3	5.5	9.8	9.8	9.8	9.8
-ROYALTY ALLOWANCE 0.0% of PCC	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-PREPRODUCTION COSTS 2% of TPC	0.258	0.195	0.148	0.126	0.109	0.195	0.195	0.195	0.195
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	13.1	10.0	7.5	6.4	5.6	10.0	10.0	10.0	10.0
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.095	0.041	0.268	0.165	0.165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	0.515	0.390	0.296	0.252	0.219	0.390	0.390	0.390	0.390
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.139	0.096	0.071	0.061	0.055	0.059	0.127	0.096	0.096
FIXED O & M COSTS ($/kW-yr) =	0.364	0.261	0.194	0.167	0.147	0.049	0.511	0.261	0.261
VARIABLE O & M COSTS (mills/kW-hr) =	0.156	0.112	0.083	0.071	0.063	0.504	0.048	0.112	0.112

NOx CONTROL COSTS - GAS/OIL BOILERS g3wfgr.wk1 FGR - WALL-FIRED UNITS (Mormile, 1987) Case 3 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	155	309	618	927	1314	77	502	309	309
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	0	0	0	0	0	0	0	0	0
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.104	0.074	0.055	0.048	0.042	0.056	0.090	0.074	0.074
-VARIABLE O & M (mills/kW-Hr)	0.156	0.112	0.083	0.071	0.063	0.504	0.048	0.112	0.112
-CONSUMABLES (mills/kW-Hr)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
-FUEL (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	1.36	1.03	0.78	0.67	0.58	1.03	1.03	1.01	1 17
LEVELIZED BUSBAR COST (mills/kW-hr) =	0.67	0.50	0.38	0.33	0.29	1.76	0.34	0.50	0 54
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-LOWER CONTROLLED NOx (lb/MMBtu)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
-LOWER NOx REDUCTION (tons/yr)	374	748	1496	2243	3178	187	1215	748	748
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	628	471	360	310	274	1650	320	465	508
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
-HIGHER NOx REDUCTION (tons/yr)	187	374	748	1122	1589	93	608	374	374
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1257	942	720	620	548	3300	640	930	1015

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g4tfgr.wk1 FGR - TANGENTIAL-FIRED UNITS (Mormile, 1987) Case 4 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	105358	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	7.76	5.88	4.46	3.79	3.22	5.88	5.88	5.88	5.88
-GENERAL FACILITIES (GF) 10% of PCC	0.78	0.59	0.45	0.38	0.32	0.59	0.59	0.59	0.59
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	0.78	0.59	0.45	0.38	0.32	0.59	0.59	0.59	0.59
-PROCESS CONTINGENCY (Proc) 10% of PCC	0.78	0.59	0.45	0.38	0.32	0.59	0.59	0.59	0.59
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	2.79	2.12	1.60	1.36	1.16	2.12	2.12	2.12	2.12
TOTAL PLANT COSTS (TPC) (1991$/kW) =	12.9	9.8	7.4	6.3	5.3	9.8	9.8	9.8	9.8
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	12.9	9.8	7.4	6.3	5.3	9.8	9.8	9.8	9.8
-ROYALTY ALLOWANCE 0.0% of PCC	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-PREPRODUCTION COSTS 2% of TPC	0.258	0.195	0.148	0.126	0.107	0.195	0.195	0.195	0.195
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	13.1	10.0	7.5	6.4	5.5	10.0	10.0	10.0	10.0
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.094	0.041	0.268	0.165	0.165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	0.515	0.390	0.296	0.252	0.214	0.390	0.390	0.390	0.390
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.139	0.096	0.071	0.061	0.054	0.059	0.127	0.096	0.096
FIXED O & M COSTS ($/kW-yr) =	0.364	0.261	0.194	0.167	0.145	0.049	0.511	0.261	0.261
VARIABLE O & M COSTS (mills/kW-hr) =	0.156	0.112	0.083	0.071	0.062	0.504	0.048	0.112	0.112

NOx CONTROL COSTS - GAS/OIL BOILERS g4tfgr.wk1 FGR - TANGENTIAL-FIRED UNITS (Mormile, 1987) Case 4 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	155	309	618	927	1391	77	502	309	309
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	0	0	0	0	0	0	0	0	0
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.104	0.074	0.055	0.048	0.041	0.056	0.090	0.074	0.074
-VARIABLE O & M (mills/kW-Hr)	0.156	0.112	0.083	0.071	0.062	0.504	0 048	0.112	0.112
-CONSUMABLES (mills/kW-Hr)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
-FUEL (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	1.36	1.03	0.78	0.67	0.57	1.03	1.03	1.01	1.17
LEVELIZED BUSBAR COST (mills/kW-hr) =	0.67	0.50	0.38	0.33	0.29	1.76	0.34	0.50	0.54
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-LOWER CONTROLLED NOx (lb/MMBtu)	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
-LOWER NOx REDUCTION (tons/yr)	187	374	748	1122	1682	93	608	374	374
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1257	942	720	620	537	3300	640	930	1015
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
-HIGHER NOx REDUCTION (tons/yr)	93	187	374	561	841	47	304	187	187
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	2514	1884	1440	1240	1074	6600	1279	1860	2031

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g5wlnb.wk1 LNB - WALL-FIRED UNITS (Mormile, 1987) Case 5 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	99505	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	22.12	16.76	12.70	10.80	9.40	16.76	16.76	16.76	16 76
-GENERAL FACILITIES (GF) 10% of PCC	2.21	1.68	1.27	1.08	0.94	1.68	1.68	1.68	1.68
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	2.21	1.68	1.27	1.08	0.94	1.68	1.68	1.68	1.68
-PROCESS CONTINGENCY (Proc) 10% of PCC	2.21	1.68	1.27	1.08	0.94	1.68	1.68	1.68	1.68
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	7.96	6.03	4.57	3.89	3.38	6.03	6.03	6.03	6.03
TOTAL PLANT COSTS (TPC) (1991$/kW) =	36.7	27.8	21.1	17.9	15.6	27.8	27.8	27.8	27.8
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	36.7	27.8	21.1	17.9	15.6	27.8	27 8	27.8	27.8
-ROYALTY ALLOWANCE 0.0% of PCC	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-PREPRODUCTION COSTS 2% of TPC	0.734	0.556	0.422	0.359	0.312	0.556	0.556	0.556	0.556
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	37.45	28.38	21.51	18.29	15.91	28.38	28.38	28 38	28 38
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.095	0.041	0.268	0.165	0 165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	1.469	1.113	0.843	0.717	0.624	1.113	1.113	1 113	1.113
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.253	0.183	0.137	0.117	0.103	0 146	0.214	0 183	0 183
FIXED O & M COSTS ($/kW-yr) =	0.791	0.584	0.440	0.375	0.329	0.130	1 037	0.584	0.584
VARIABLE O & M COSTS (mills/kW-hr) =	0.339	0.250	0.188	0.161	0.141	1.336	0 098	0.250	0 250

NOx CONTROL COSTS - GAS/OIL BOILERS g5wlnb.wk1 LNB - WALL-FIRED UNITS (Mormile, 1987) Case 5 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	0	0	0	0	0	0	0	0	0
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0 000
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.226	0.167	0.126	0.107	0.094	0.148	0.182	0.167	0.167
-VARIABLE O & M (mills/kW-Hr)	0.339	0.250	0.188	0.161	0.141	1.336	0.098	0.250	0.250
-CONSUMABLES (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-FUEL (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0 000
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	3.88	2.94	2.23	1.90	1.65	2.94	2.94	2 88	3.33
LEVELIZED BUSBAR COST (mills/kW-hr) =	1.67	1.26	0.95	0.81	0.71	4.84	0.80	1.24	1.37
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-LOWER CONTROLLED NOx (lb/MMBtu)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
-LOWER NOx REDUCTION (tons/yr)	374	748	1496	2243	3178	187	1215	748	748
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1568	1178	891	758	661	4539	747	1160	1282
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-HIGHER NOx REDUCTION (tons/yr)	280	561	1122	1682	2383	140	911	561	561
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	2090	1570	1187	1011	881	6053	996	1547	1710

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g6tlnb.wk1 LNB - TANGENTIAL-FIRED UNITS (Mormile, 1987) Case 6 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	105358	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	22.12	16.76	12.70	10.80	9.18	16.76	16.76	16.76	16.76
-GENERAL FACILITIES (GF) 10% of PCC	2.21	1.68	1.27	1.08	0.92	1.68	1.68	1.68	1.68
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	2.21	1.68	1.27	1.08	0.92	1.68	1.68	1.68	1.68
-PROCESS CONTINGENCY (Proc) 10% of PCC	2.21	1.68	1.27	1.08	0.92	1.68	1.68	1.68	1.68
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	7.96	6.03	4.57	3.89	3.31	6.03	6.03	6.03	6.03
TOTAL PLANT COSTS (TPC) (1991$/kW) =	36.7	27.8	21.1	17.9	15.2	27.8	27.8	27.8	27.8
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	36.7	27.8	21.1	17.9	15.2	27.8	27.8	27.8	27.8
-ROYALTY ALLOWANCE 0.0% of PCC	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-PREPRODUCTION COSTS 2% of TPC	0.734	0.556	0.422	0.359	0.305	0.556	0.556	0.556	0.556
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	37.45	28.38	21.51	18.29	15.55	28.38	28.38	28.38	28.38
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.094	0.041	0.268	0.165	0.165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	1.469	1.113	0.843	0.717	0.610	1.113	1.113	1.113	1.113
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.253	0.183	0.137	0.117	0.101	0.146	0.214	0.183	0.183
FIXED O & M COSTS ($/kW-yr) =	0.791	0.584	0.440	0.375	0.322	0.130	1.037	0.584	0.584
VARIABLE O & M COSTS (mills/kW-hr) =	0.339	0.250	0.188	0.161	0.138	1.336	0.098	0.250	0.250

NOx CONTROL COSTS - GAS/OIL BOILERS g6tlnb.wk1 LNB - TANGENTIAL-FIRED UNITS (Mormile, 1987) Case 6 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	0	0	0	0	0	0	0	0	0
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0 000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.226	0.167	0.126	0.107	0.092	0.148	0.182	0.167	0.167
-VARIABLE O & M (mills/kW-Hr)	0.339	0.250	0.188	0.161	0.138	1.336	0.098	0.250	0.250
-CONSUMABLES (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-FUEL (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	3.88	2.94	2.23	1.90	1.61	2.94	2.94	2.88	3.33
LEVELIZED BUSBAR COST (mills/kW-hr) =	1.67	1.26	0.95	0.81	0.69	4.84	0.80	1.24	1.37
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-LOWER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0 15
-LOWER NOx REDUCTION (tons/yr)	280	561	1122	1682	2524	140	911	561	561
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	2090	1570	1187	1011	862	6053	996	1547	1710
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0 25
-HIGHER NOx REDUCTION (tons/yr)	93	187	374	561	841	47	304	187	187
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	6271	4711	3562	3033	2586	18158	2988	4642	5130

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g7wbofg.wk1 BOOS + FGR - WALL-FIRED UNITS (Mormile, 1987) Case 7 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	99505	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	8.25	6.25	4.74	4.03	3.51	6.25	6.25	6 25	6 25
-GENERAL FACILITIES (GF) 10% of PCC	0.83	0.63	0.47	0.40	0.35	0.63	0.63	0.63	0.63
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	0.83	0.63	0.47	0.40	0.35	0.63	0.63	0.63	0 63
-PROCESS CONTINGENCY (Proc) 10% of PCC	0.83	0.63	0.47	0.40	0 35	0.63	0.63	0.63	0.63
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	2.97	2.25	1.71	1.45	1.26	2.25	2.25	2 25	2 25
TOTAL PLANT COSTS (TPC) (1991$/kW) =	13.7	10.4	7.9	6.7	5.8	10.4	10.4	10.4	10.4
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	13.7	10.4	7.9	6.7	5.8	10.4	10.4	10.4	10.4
-ROYALTY ALLOWANCE 0.0% of PCC	0.000	0.000	0.000	0.000	0 000	0 000	0.000	0.000	0.000
-PREPRODUCTION COSTS 2% of TPC	0.274	0.208	0.157	0.134	0.116	0.208	0.208	0.208	0.208
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	14.0	10.6	8.0	6.8	5.9	10.6	10.6	10.6	10.6
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.095	0.041	0.268	0 165	0 165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	0.548	0.415	0.315	0.268	0.233	0.415	0.415	0 415	0 415
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.143	0.099	0.073	0.063	0.056	0.062	0.130	0 099	0 099
FIXED O & M COSTS ($/kW-yr) =	0.379	0.272	0.203	0.174	0.154	0.052	0.529	0.272	0 272
VARIABLE O & M COSTS (mills/kW-hr) =	0.162	0.116	0.087	0.074	0.066	0 533	0 050	0.116	0.116

NOx CONTROL COSTS - GAS/OIL BOILERS g7wbofg.wk1 BOOS + FGR - WALL-FIRED UNITS (Mormile, 1987) Case 7 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	155	309	618	927	1314	77	502	309	309
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	1192	2384	4769	7153	10134	596	3875	2384	2384
-GAS (1000 ft^3/yr)	3879	7758	15517	23275	32973	1940	12607	7758	7758
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078
-GAS (mills/kW-hr)	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.108	0.078	0.058	0.050	0.044	0.059	0.093	0.078	0.078
-VARIABLE O & M (mills/kW-Hr)	0.162	0.116	0.087	0.074	0.066	0.533	0.050	0.116	0.116
-CONSUMABLES (mills/kW-Hr)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
-FUEL (mills/kW-Hr)	0.107	0.107	0.107	0.107	0.107	0.107	0.107	0.107	0.107
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	1.45	1.10	0.83	0.71	0.62	1.10	1 10	1.07	1 24
LEVELIZED BUSBAR COST (mills/kW-hr) =	0.81	0.64	0.51	0.45	0.41	1.97	0.46	0.63	0.68
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-LOWER CONTROLLED NOx (lb/MMBtu)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
-LOWER NOx REDUCTION (tons/yr)	374	748	1496	2243	3178	187	1215	748	748
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	761	596	479	426	388	1850	435	590	635
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-HIGHER NOx REDUCTION (tons/yr)	280	561	1122	1682	2383	140	911	561	561
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1015	795	639	568	517	2467	580	786	847

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g8tbofg.wk1 BOOS + FGR - TANGENTIAL-FIRED UNITS (Mormile, 1987) Case 8 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	105358	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	8.25	6.25	4.74	4.03	3.43	6.25	6.25	6.25	6 25
-GENERAL FACILITIES (GF) 10% of PCC	0.83	0.63	0.47	0.40	0.34	0.63	0.63	0.63	0 63
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	0.83	0.63	0.47	0.40	0.34	0.63	0.63	0.63	0.63
-PROCESS CONTINGENCY (Proc) 10% of PCC	0.83	0.63	0.47	0.40	0.34	0.63	0.63	0.63	0 63
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	2.97	2.25	1.71	1.45	1.23	2.25	2.25	2.25	2.25
TOTAL PLANT COSTS (TPC) (1991$/kW) =	13.7	10.4	7.9	6.7	5.7	10 4	10.4	10.4	10.4
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	13.7	10.4	7.9	6.7	5.7	10.4	10.4	10.4	10.4
-ROYALTY ALLOWANCE 0.0% of PCC	0.000	0.000	0.000	0.000	0.000	0 000	0.000	0 000	0.000
-PREPRODUCTION COSTS 2% of TPC	0.274	0.208	0.157	0.134	0.114	0.208	0.208	0.208	0.208
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	14.0	10.6	8.0	6.8	5.8	10 6	10.6	10.6	10.6
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.094	0.041	0 268	0.165	0 165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	0.548	0.415	0.315	0.268	0.228	0.415	0 415	0 415	0 415
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.143	0.099	0.073	0.063	0.055	0.062	0 130	0 099	0.099
FIXED O & M COSTS ($/kW-yr) =	0.379	0.272	0.203	0.174	0.151	0.052	0.529	0.272	0.272
VARIABLE O & M COSTS (mills/kW-hr) =	0.162	0.116	0.087	0.074	0.064	0.533	0.050	0.116	0 116

NOx CONTROL COSTS - GAS/OIL BOILERS g8tbofg.wk1 BOOS + FGR - TANGENTIAL-FIRED UNITS (Mormile, 1987) Case 8 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	155	309	618	927	1391	77	502	309	309
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	1192	2384	4769	7153	10730	596	3875	2384	2384
-GAS (1000 ft^3/yr)	3879	7758	15517	23275	34912	1940	12607	7758	7758
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0 022
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078
-GAS (mills/kW-hr)	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.108	0.078	0.058	0.050	0.043	0.059	0.093	0.078	0 078
-VARIABLE O & M (mills/kW-Hr)	0.162	0.116	0.087	0.074	0.064	0.533	0.050	0.116	0.116
-CONSUMABLES (mills/kW-Hr)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0 022
-FUEL (mills/kW-Hr)	0.107	0.107	0.107	0.107	0.107	0.107	0.107	0.107	0 107
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	1.45	1.10	0.83	0.71	0.60	1.10	1.10	1.07	1.24
LEVELIZED BUSBAR COST (mills/kW-hr) =	0.81	0.64	0.51	0.45	0.41	1.97	0.46	0.63	0.68
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-LOWER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-LOWER NOx REDUCTION (tons/yr)	280	561	1122	1682	2524	140	911	561	561
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1015	795	639	568	510	2467	580	786	847
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
-HIGHER NOx REDUCTION (tons/yr)	187	374	748	1122	1682	93	608	374	374
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1523	1192	958	852	765	3701	870	1179	1270

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g9wlnfgo.wk1 LNB + FGR + OFA - WALL-FIRED UNITS (Carnevale/Yee, 1989) Case 9 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	99505	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	42.70	32.36	24.52	20.85	18.14	32.36	32.36	32.36	32.36
-GENERAL FACILITIES (GF) 10% of PCC	4.27	3.24	2.45	2.09	1.81	3.24	3 24	3.24	3.24
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	4.27	3.24	2.45	2.09	1.81	3.24	3.24	3.24	3.24
-PROCESS CONTINGENCY (Proc) 10% of PCC	4.27	3.24	2.45	2.09	1.81	3.24	3.24	3.24	3.24
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	15.37	11.65	8.83	7.51	6.53	11.65	11.65	11 65	11 65
TOTAL PLANT COSTS (TPC) (1991$/kW) =	70.9	53.7	40.7	34.6	30.1	53.7	53.7	53.7	53 7
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	70.9	53.7	40.7	34.6	30.1	53.7	53.7	53.7	53 7
-ROYALTY ALLOWANCE 0.0% of PCC	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0 000
-PREPRODUCTION COSTS 2% of TPC	1.418	1.074	0.814	0.692	0.602	1.074	1.074	1.074	1 074
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	72.3	54.8	41.5	35.3	30.7	54 8	54 8	54.8	54.8
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.095	0 041	0.268	0.165	0.165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	2.835	2.149	1.628	1.385	1.205	2 149	2.149	2.149	2 149
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.417	0.307	0.231	0.197	0.173	0.270	0 338	0.307	0.307
FIXED O & M COSTS ($/kW-yr) =	1.404	1.048	0.791	0.674	0.589	0.246	1.791	1.048	1.048
VARIABLE O & M COSTS (mills/kW-hr) =	0.601	0.449	0.339	0.289	0.252	2.527	0 169	0.449	0.449

NOx CONTROL COSTS - GAS/OIL BOILERS g9wlnfgo.wk1 LNB + FGR + OFA - WALL-FIRED UNITS (Carnevale/Yee, 1989) Case 9 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	155	309	618	927	1314	77	502	309	309
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	1987	3974	7948	11922	16890	994	6458	3974	3974
-GAS (1000 ft^3/yr)	6465	12931	25861	38792	54955	3233	21012	12931	12931
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.130	0.130	0.130	0.130	0.130	0.130	0.130	0.130	0.130
-GAS (mills/kW-hr)	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.401	0.299	0.226	0.192	0.168	0.281	0.314	0.299	0.299
-VARIABLE O & M (mills/kW-Hr)	0.601	0.449	0.339	0.289	0.252	2.527	0.169	0.449	0.449
-CONSUMABLES (mills/kW-Hr)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
-FUEL (mills/kW-Hr)	0.178	0.178	0.178	0.178	0.178	0.178	0.178	0.178	0.178
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	7.50	5.68	4.31	3.66	3.18	5.68	5.68	5.56	6.44
LEVELIZED BUSBAR COST (mills/kW-hr) =	3.34	2.57	1.99	1.73	1.53	9.49	1.68	2.53	2.78
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	654	1309	2617	3926	5561	327	2126	1309	1309
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1789	1376	1067	924	819	5084	900	1357	1491
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
-HIGHER NOx REDUCTION (tons/yr)	374	748	1496	2243	3178	187	1215	748	748
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3131	2408	1868	1617	1433	8897	1576	2374	2610

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g10tlnfo.wk1 LNB+FGR+OFA - TANGENTIAL-FIRED UNITS (Carnevale/Yee, 1989) Case 10 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	105358	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	42.70	32.36	24.52	20.85	17.73	32.36	32.36	32.36	32.36
-GENERAL FACILITIES (GF) 10% of PCC	4.27	3.24	2.45	2.09	1.77	3.24	3.24	3.24	3.24
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	4.27	3.24	2.45	2.09	1.77	3.24	3.24	3.24	3.24
-PROCESS CONTINGENCY (Proc) 10% of PCC	4.27	3.24	2.45	2.09	1.77	3.24	3.24	3.24	3.24
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 30%	15.37	11.65	8.83	7.51	6.38	11.65	11.65	11.65	11.65
TOTAL PLANT COSTS (TPC) (1991$/kW) =	70.9	53.7	40.7	34.6	29.4	53.7	53.7	53.7	53.7
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	70.9	53.7	40.7	34.6	29.4	53.7	53.7	53.7	53.7
-ROYALTY ALLOWANCE 0.0% of PCC	0.000	0.000	0.000	0.000	0.000	0.000	0 000	0.000	0.000
-PREPRODUCTION COSTS 2% of TPC	1.418	1.074	0.814	0.692	0.589	1.074	1.074	1.074	1.074
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	72.3	54.8	41.5	35.3	30.0	54.8	54 8	54.8	54 8
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.094	0.041	0.268	0.165	0.165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	2.835	2.149	1.628	1.385	1.177	2.149	2 149	2.149	2.149
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.417	0.307	0.231	0.197	0.169	0.270	0.338	0.307	0.307
FIXED O & M COSTS ($/kW-yr) =	1.404	1.048	0.791	0.674	0.576	0.246	1 791	1.048	1 048
VARIABLE O & M COSTS (mills/kW-hr) =	0.601	0.449	0.339	0.289	0.247	2.527	0.169	0.449	0 449

NOx CONTROL COSTS - GAS/OIL BOILERS g10tlnfo.wk1 LNB+FGR+OFA - TANGENTIAL-FIRED UNITS (Carnevale/Yee, 1989) Case 10 SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	155	309	618	927	1391	77	502	309	309
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	1987	3974	7948	11922	17883	994	6458	3974	3974
-GAS (1000 ft^3/yr)	6465	12931	25861	38792	58187	3233	21012	12931	12931
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.130	0.130	0.130	0.130	0.130	0.130	0.130	0.130	0.130
-GAS (mills/kW-hr)	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0 048
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.401	0.299	0.226	0.192	0.164	0.281	0.314	0.299	0.299
-VARIABLE O & M (mills/kW-Hr)	0.601	0.449	0.339	0.289	0.247	2.527	0.169	0.449	0.449
-CONSUMABLES (mills/kW-Hr)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022
-FUEL (mills/kW-Hr)	0.178	0.178	0.178	0.178	0.178	0.178	0.178	0.178	0.178
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	7.50	5.68	4.31	3.66	3.11	5.68	5.68	5.56	6.44
LEVELIZED BUSBAR COST (mills/kW-hr) =	3.34	2.57	1.99	1.73	1.50	9.49	1.68	2.53	2.78
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	374	748	1496	2243	3365	187	1215	748	748
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3131	2408	1868	1617	1405	8897	1576	2374	2610
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
-HIGHER NOx REDUCTION (tons/yr)	187	374	748	1122	1682	93	608	374	374
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	6262	4816	3736	3235	2810	17795	3152	4748	5219

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g11wsncu.wk1	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
UREA NOx-OUT (SNCR-UNCONTROLLED) - WALL									
(Springer, 1992) Case 11 | SIZE (MW)	100	200	400	600	850	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	99505	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	6.60	5.00	3.79	3.22	2.80	5.00	5.00	5 00	5.00
-GENERAL FACILITIES (GF) 10% of PCC	0.66	0.50	0.38	0.32	0.28	0.50	0.50	0.50	0.50
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	0.66	0.50	0.38	0.32	0.28	0.50	0.50	0.50	0.50
-PROCESS CONTINGENCY (Proc) 10% of PCC	0.66	0.50	0.38	0.32	0.28	0.50	0.50	0.50	0.50
-PROJECT CONTINGENCY (% of PCC) 30%	1.98	1.50	1.14	0.97	0.84	1.50	1.50	1.50	1.50
TOTAL PLANT COSTS (TPC) (1991$/kW) =	11	8	6	5	4	8	8	8	8
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	11	8	6	5	4	8	8	8	8
-ROYALTY ALLOWANCE	2.55	1.68	0.84	0.57	0.41	0.25	0.25	0.25	0 25
-PREPRODUCTION COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	13	10	7	6	5	8	8	8	8
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.131	0.066	0.033	0.022	0.015	0.263	0.040	0.066	0 066
-MAINTENANCE COSTS (MC) ($/kW-yr)	0.069	0.034	0.017	0.011	0.008	0 137	0.021	0.034	0.034
-ADMIN/SUPPORT LABOR ($/kW-yr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FIXED O & M COSTS ($/kW-yr) =	0.08	0.04	0.02	0.01	0.01	0.04	0.04	0.04	0.04
VARIABLE O & M COSTS (mills/kW-hr) =	0.034	0.017	0.009	0.006	0.004	0.411	0 004	0 017	0.017

NOx CONTROL COSTS - GAS/OIL BOILERS g11wsncu.wk1 UREA NOx-OUT (SNCR-UNCONTROLLED) - WALL (Springer, 1992) Case 11 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	823	1646	3292	4938	6995	411	2675	1646	1646
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	397	795	1590	2384	3378	199	1292	795	795
-GAS (1000 ft^3/yr)	1293	2586	5172	7758	10991	647	4202	2586	2586
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026
-GAS (mills/kW-hr)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.023	0.011	0.006	0.004	0.003	0.046	0.007	0.011	0.011
-VARIABLE O & M (mills/kW-Hr)	0.034	0.017	0.009	0.006	0.004	0.411	0.004	0.017	0.017
-CONSUMABLES (mills/kW-Hr)	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517	0.517
-FUEL (mills/kW-Hr)	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	1.36	1.00	0.72	0.59	0.51	0.86	0.86	0.84	0.97
LEVELIZED BUSBAR COST (mills/kW-hr) =	1.00	0.87	0.77	0.73	0.70	1.99	0.71	0.82	0.86
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-LOWER CONTROLLED NOx (lb/MMBtu)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
-LOWER NOx REDUCTION (tons/yr)	374	748	1496	2243	3178	187	1215	748	748
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	935	813	722	685	659	1861	668	768	804
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-HIGHER NOx REDUCTION (tons/yr)	280	561	1122	1682	2383	140	911	561	561
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1246	1084	963	914	879	2481	891	1024	1071

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g12wsncc.wk1 UREA NOx-OUT (SNCR-CONTROLLED) - WALL (Springer, 1992) Case 12 SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	99505	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	6.60	5.00	3.79	3.22	2.80	5.00	5.00	5.00	5.00
-GENERAL FACILITIES (GF) 10% of PCC	0.66	0.50	0.38	0.32	0.28	0.50	0.50	0.50	0.50
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	0.66	0.50	0.38	0.32	0.28	0.50	0.50	0.50	0.50
-PROCESS CONTINGENCY (Proc) 10% of PCC	0.66	0.50	0.38	0.32	0.28	0.50	0.50	0.50	0.50
-PROJECT CONTINGENCY (% of PCC) 30%	1.98	1.50	1.14	0.97	0.84	1.50	1.50	1.50	1.50
TOTAL PLANT COSTS (TPC) (1991$/kW) =	11	8	6	5	4	8	8	8	8
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	11	8	6	5	4	8	8	8	8
-ROYALTY ALLOWANCE	2.55	1.68	0.84	0.57	0.41	0.25	0.25	0.25	0.25
-PREPRODUCTION COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	13	10	7	6	5	8	8	8	8
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.131	0.066	0.033	0.022	0.015	0.263	0.040	0.066	0.066
-MAINTENANCE COSTS (MC) ($/kW-yr)	0.069	0.034	0.017	0.011	0.008	0.137	0.021	0.034	0.034
-ADMIN/SUPPORT LABOR ($/kW-yr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FIXED O & M COSTS ($/kW-yr) =	0.08	0.04	0.02	0.01	0.01	0.04	0.04	0.04	0.04
VARIABLE O & M COSTS (mills/kW-hr) =	0.034	0.017	0.009	0.006	0.004	0.411	0.004	0.017	0.017

NOx CONTROL COSTS - GAS/OIL BOILERS g12wsncc.wk1 UREA NOx-OUT (SNCR-CONTROLLED) - WALL (Springer, 1992) Case 12 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	549	1097	2194	3292	4663	274	1783	1097	1097
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	397	795	1590	2384	3378	199	1292	795	795
-GAS (1000 ft^3/yr)	1293	2586	5172	7758	10991	647	4202	2586	2586
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026
-GAS (mills/kW-hr)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.023	0.011	0.006	0.004	0.003	0.046	0 007	0.011	0.011
-VARIABLE O & M (mills/kW-Hr)	0.034	0.017	0.009	0.006	0.004	0.411	0.004	0.017	0.017
-CONSUMABLES (mills/kW-Hr)	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0 344
-FUEL (mills/kW-Hr)	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	1.36	1.00	0.72	0.59	0.51	0.86	0.86	0 84	0 97
LEVELIZED BUSBAR COST (mills/kW-hr) =	0.82	0.69	0.60	0.56	0.53	1.81	0.54	0.65	0.69
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0 30
-LOWER CONTROLLED NOx (lb/MMBtu)	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
-LOWER NOx REDUCTION (tons/yr)	187	374	748	1122	1589	93	608	374	374
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1546	1302	1122	1047	996	3399	1014	1213	1284
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
-HIGHER NOx REDUCTION (tons/yr)	93	187	374	561	794	47	304	187	187
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	3093	2605	2244	2095	1992	6798	2028	2427	2568

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g13tsncu.wk1 UREA NOx-OUT (SNCR-UNCONTR) -TANGENTIAL (Springer, 1992) Case 13 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	105358	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	6.60	5.00	3.79	3.22	2.74	5.00	5.00	5.00	5.00
-GENERAL FACILITIES (GF) 10% of PCC	0.66	0.50	0.38	0.32	0.27	0.50	0.50	0.50	0.50
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	0.66	0.50	0.38	0.32	0.27	0.50	0.50	0.50	0.50
-PROCESS CONTINGENCY (Proc) 10% of PCC	0.66	0.50	0.38	0.32	0.27	0.50	0.50	0.50	0.50
-PROJECT CONTINGENCY (% of PCC) 30%	1.98	1.50	1.14	0.97	0.82	1.50	1.50	1.50	1.50
TOTAL PLANT COSTS (TPC) (1991$/kW) =	11	8	6	5	4	8	8	8	8
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	11	8	6	5	4	8	8	8	8
-ROYALTY ALLOWANCE	2.55	1.68	0.84	0.57	0.38	0.25	0.25	0.25	0.25
-PREPRODUCTION COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	13	10	7	6	5	8	8	8	8
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.131	0.066	0.033	0.022	0.015	0.263	0.040	0.066	0.066
-MAINTENANCE COSTS (MC) ($/kW-yr)	0.069	0.034	0.017	0.011	0.008	0.137	0.021	0.034	0.034
-ADMIN/SUPPORT LABOR ($/kW-yr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FIXED O & M COSTS ($/kW-yr) =	0.08	0.04	0.02	0.01	0.01	0.04	0.04	0.04	0.04
VARIABLE O & M COSTS (mills/kW-hr) =	0.034	0.017	0.009	0.006	0.004	0.411	0.004	0.017	0.017

NOx CONTROL COSTS - GAS/OIL BOILERS g13tsncu.wk1 UREA NOx-OUT (SNCR-UNCONTR) -TANGENTIAL (Springer, 1992) Case 13 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	549	1097	2194	3292	4938	274	1783	1097	1097
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	397	795	1590	2384	3577	199	1292	795	795
-GAS (1000 ft^3/yr)	1293	2586	5172	7758	11637	647	4202	2586	2586
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026
-GAS (mills/kW-hr)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.023	0.011	0.006	0.004	0.003	0.046	0.007	0.011	0.011
-VARIABLE O & M (mills/kW-Hr)	0.034	0.017	0.009	0.006	0.004	0.411	0.004	0.017	0.017
-CONSUMABLES (mills/kW-Hr)	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344	0.344
-FUEL (mills/kW-Hr)	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	1.36	1.00	0.72	0.59	0.49	0.86	0.86	0.84	0.97
LEVELIZED BUSBAR COST (mills/kW-hr) =	0.82	0.69	0.60	0.56	0.53	1.81	0.54	0.65	0.69
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-LOWER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-LOWER NOx REDUCTION (tons/yr)	280	561	1122	1682	2524	140	911	561	561
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1031	868	748	698	659	2266	676	809	856
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
-HIGHER NOx REDUCTION (tons/yr)	187	374	748	1122	1682	93	608	374	374
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1546	1302	1122	1047	989	3399	1014	1213	1284

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS gl4tsncc.wk1	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
UREA NOx-OUT (SNCR-CONTROL) -TANGENTIAL									
(Springer, 1992) Case 14 | SIZE (MW)	100	200	400	600	900	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	105358	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CATALYST LIFE (yrs)	0	0	0	0	0	0	0	0	0
CATALYST VOLUME (ft^3)	0	0	0	0	0	0	0	0	0
UREA NSR (molar)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	----	-----	-----	-----	-----	-----	-----	-----	-----
-Fan Upgrade/Replace	----	-----	-----	-----	-----	-----	-----	-----	-----
-Structural	----	-----	-----	-----	-----	-----	-----	-----	-----
-Reagent Storage & Distribution	----	-----	-----	-----	-----	-----	-----	-----	-----
-DeNOx Reactor/Catalyst	----	-----	-----	-----	-----	-----	-----	-----	-----
-Control System	----	-----	-----	-----	-----	-----	-----	-----	-----
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	----	-----	-----	-----	-----	-----	-----	-----	-----
-Construction/Installation Labor	----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	6.60	5.00	3.79	3.22	2.74	5.00	5.00	5.00	5.00
-GENERAL FACILITIES (GF) 10% of PCC	0.66	0.50	0.38	0.32	0.27	0.50	0.50	0.50	0.50
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	0.66	0.50	0.38	0.32	0.27	0.50	0.50	0.50	0.50
-PROCESS CONTINGENCY (Proc) 10% of PCC	0.66	0.50	0.38	0.32	0.27	0.50	0.50	0.50	0.50
-PROJECT CONTINGENCY (% of PCC) 30%	1.98	1.50	1.14	0.97	0.82	1.50	1.50	1.50	1.50
TOTAL PLANT COSTS (TPC) (1991$/kW) =	11	8	6	5	4	8	8	8	8
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	11	8	6	5	4	8	8	8	8
-ROYALTY ALLOWANCE	2.55	1.68	0.84	0.57	0.38	0.25	0.25	0.25	0.25
-PREPRODUCTION COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	13	10	7	6	5	8	8	8	8
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.131	0.066	0.033	0.022	0.015	0.263	0.040	0.066	0.066
-MAINTENANCE COSTS (MC) ($/kW-yr)	0.069	0.034	0.017	0.011	0.008	0.137	0.021	0.034	0.034
-ADMIN/SUPPORT LABOR ($/kW-yr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
FIXED O & M COSTS ($/kW-yr) =	0.08	0.04	0.02	0.01	0.01	0.04	0.04	0.04	0.04
VARIABLE O & M COSTS (mills/kW-hr) =	0.034	0.017	0.009	0.006	0.004	0.411	0.004	0.017	0.017

NOx CONTROL COSTS - GAS/OIL BOILERS g14tsncc.wk1 UREA NOx-OUT (SNCR-CONTROL) -TANGENTIAL (Springer, 1992) Case 14 SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	0	0	0	0	0	0	0	0	0
-UREA (tons/yr)	366	731	1463	2194	3292	183	1189	731	731
-ELECTRICITY (MW-hrs/yr)	0	0	0	0	0	0	0	0	0
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	397	795	1590	2384	3577	199	1292	795	795
-GAS (1000 ft^3/yr)	1293	2586	5172	7758	11637	647	4202	2586	2586
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-UREA (mills/kW-hr)	0.230	0.230	0.230	0.230	0.230	0.230	0.230	0.230	0.230
-ELECTRICITY (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	0.230	0.230	0.230	0.230	0.230	0.230	0.230	0.230	0 230
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026
-GAS (mills/kW-hr)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.023	0.011	0.006	0.004	0.003	0.046	0.007	0.011	0.011
-VARIABLE O & M (mills/kW-Hr)	0.034	0.017	0.009	0.006	0.004	0.411	0.004	0.017	0.017
-CONSUMABLES (mills/kW-Hr)	0.230	0.230	0.230	0.230	0.230	0.230	0.230	0.230	0.230
-FUEL (mills/kW-Hr)	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	1.36	1.00	0.72	0.59	0.49	0.86	0.86	0.84	0.97
LEVELIZED BUSBAR COST (mills/kW-hr) =	0.71	0.58	0.48	0.44	0.41	1.70	0.43	0.53	0 57
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	187	374	748	1122	1682	93	608	374	374
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	1331	1087	907	832	773	3184	799	998	1069
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
-HIGHER NOx REDUCTION (tons/yr)	93	187	374	561	841	47	304	187	187
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	2662	2174	1813	1665	1547	6368	1598	1996	2138

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g15wscru.wk1 SCR - UNCONTROLLED - WALL-FIRED UNITS (Johnson, 1991) Case 15 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	99505	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	1951	3902	7804	11706	16584	3902	3902	3902	3902
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	4.51	3.41	2.59	2.20	1.91	3.41	3.41	3.41	3 41
-Fan Upgrade/Replace	12.85	9.74	7.38	6.28	5.46	9.74	9.74	9.74	9.74
-Structural	13.41	10.16	7.70	6.55	5.70	10.16	10.16	10.16	10.16
-Reagent Storage & Distribution	8.00	6.06	4.60	3.91	3.40	6.06	6.06	6.06	6 06
-DeNOx Reactor/Catalyst	32.02	24.27	18.39	15.64	13.60	24.27	24.27	24.27	24 27
-Control System	6.61	5.01	3.79	3.23	2.81	5.01	5.01	5.01	5.01
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	19.53	14.80	11.22	9.54	8.30	14.80	14 80	14 80	14.80
-Construction/Installation Labor	0.77	0.59	0.44	0.38	0.33	0.59	0.59	0.59	0.59
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	97.70	74.04	56.11	47.71	41.51	74.04	74.04	74.04	74.04
-GENERAL FACILITIES (GF) 10% of PCC	9.77	7.40	5.61	4.77	4.15	7.40	7.40	7.40	7.40
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	9.77	7.40	5.61	4.77	4.15	7.40	7 40	7.40	7 40
-PROCESS CONTINGENCY (Proc) 10% of PCC	9.77	7.40	5.61	4.77	4.15	7.40	7.40	7.40	7.40
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 40%	46.90	35.54	26.93	22.90	19.92	35.54	35 54	35.54	35.54
TOTAL PLANT COSTS (TPC) (1991$/kW) =	174	132	100	85	74	132	132	132	132
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	174	132	100	85	74	132	132	132	132
-ROYALTY ALLOWANCE 0.5% of PCC	0.49	0.37	0.28	0.24	0.21	0.37	0.37	0.37	0 37
-PREPRODUCTION COSTS 2% of TPC	3.48	2.64	2.00	1.70	1.48	2.64	2.64	2.64	2 64
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	178	135	102	87	76	135	135	135	135
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.095	0.041	0.268	0.165	0.165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	6.956	5.272	3.995	3.397	2.955	5 272	5.272	5.272	5.272
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.912	0.682	0.515	0.439	0.383	0.645	0.713	0 682	0.682
FIXED O & M COSTS ($/kW-yr) =	3.25	2.45	1.85	1.58	1.37	0.60	4 06	2.45	2 45
VARIABLE O & M COSTS (mills/kW-hr) =	1.391	1.048	0.793	0.675	0.588	6.121	0 384	1.048	1 048

NOx CONTROL COSTS - GAS/OIL BOILERS g15wscru.wk1 SCR - UNCONTROLLED - WALL-FIRED UNITS (Johnson, 1991) Case 15 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	311	623	1246	1868	2647	156	1012	623	623
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3291	8237	18129	28020	40385	2059	13385	8237	8237
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	0	0	0	0	0	0	0	0	0
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.129	0.129	0.129	0.129	0.129	0.129	0.129	0.129	0.129
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.470	0.588	0.647	0.666	0.678	0.588	0.588	0.588	0.588
-CATALYST (mills/kW-hr)	0.919	0.919	0.919	0.919	0.919	3.675	0.565	0.919	0.919
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.011	0.011	0.011	0.011	0.011	0.042	0.006	0.011	0.011
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.528	1.646	1.705	1.725	1.736	4.434	1.288	1.646	1.646
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.927	0.698	0.528	0.450	0.392	0.680	0.714	0.698	0.698
-VARIABLE O & M (mills/kW-Hr)	1.391	1.048	0.793	0.675	0.588	6.121	0.384	1.048	1.048
-CONSUMABLES (mills/kW-Hr)	1.528	1.646	1.705	1.725	1.736	4.434	1.288	1.646	1.646
-FUEL (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	18.44	13.98	10.59	9.01	7.84	13.98	13.98	13.67	15 83
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.11	7.38	6.05	5.42	4.95	27.19	4.84	7.29	7 91
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
-LOWER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-LOWER NOx REDUCTION (tons/yr)	654	1309	2617	3926	5561	327	2126	1309	1309
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	4879	3953	3240	2902	2652	14562	2593	3906	4237
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0 15
-HIGHER NOx REDUCTION (tons/yr)	561	1122	2243	3365	4767	280	1823	1122	1122
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	5692	4612	3780	3386	3094	16989	3025	4556	4943

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g16wscrc.wk1 SCR - CONTROLLED - WALL-FIRED UNITS (Johnson, 1991) Case 16 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	99505	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	1951	3902	7804	11706	16584	3902	3902	3902	3902
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	4.51	3.41	2.59	2.20	1.91	3.41	3.41	3.41	3.41
-Fan Upgrade/Replace	12.85	9.74	7.38	6.28	5.46	9.74	9.74	9.74	9.74
-Structural	13.41	10.16	7.70	6.55	5.70	10.16	10.16	10.16	10.16
-Reagent Storage & Distribution	8.00	6.06	4.60	3.91	3.40	6.06	6.06	6.06	6 06
-DeNOx Reactor/Catalyst	32.02	24.27	18.39	15.64	13.60	24.27	24.27	24.27	24.27
-Control System	6.61	5.01	3.79	3.23	2.81	5.01	5.01	5.01	5.01
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	19.53	14.80	11.22	9.54	8.30	14.80	14.80	14.80	14 80
-Construction/Installation Labor	0.77	0.59	0.44	0.38	0.33	0.59	0.59	0.59	0.59
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	97.70	74.04	56.11	47.71	41.51	74.04	74.04	74.04	74 04
-GENERAL FACILITIES (GF) 10% of PCC	9.77	7.40	5.61	4.77	4.15	7.40	7.40	7.40	7 40
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	9.77	7.40	5.61	4.77	4.15	7.40	7.40	7.40	7.40
-PROCESS CONTINGENCY (Proc) 10% of PCC	9.77	7.40	5.61	4.77	4.15	7.40	7.40	7 40	7.40
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 40%	46.90	35.54	26.93	22.90	19.92	35.54	35.54	35.54	35 54
TOTAL PLANT COSTS (TPC) (1991$/kW) =	174	132	100	85	74	132	132	132	132
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	174	132	100	85	74	132	132	132	132
-ROYALTY ALLOWANCE 0.5% of PCC	0.49	0.37	0.28	0.24	0.21	0.37	0.37	0.37	0.37
-PREPRODUCTION COSTS 2% of TPC	3.48	2.64	2.00	1.70	1.48	2.64	2.64	2.64	2 64
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	178	135	102	87	76	135	135	135	135
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.095	0.041	0.268	0.165	0 165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	6.956	5.272	3.995	3.397	2.955	5.272	5 272	5.272	5.272
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.912	0.682	0.515	0.439	0.383	0.645	0.713	0.682	0 682
FIXED O & M COSTS ($/kW-yr) =	3.25	2.45	1.85	1.58	1.37	0.60	4 06	2.45	2 45
VARIABLE O & M COSTS (mills/kW-hr) =	1.391	1.048	0.793	0.675	0.588	6.121	0.384	1 048	1 048

NOx CONTROL COSTS - GAS/OIL BOILERS g16wscrc.wk1 SCR - CONTROLLED - WALL-FIRED UNITS (Johnson, 1991) Case 16 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	850	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	208	415	830	1246	1765	104	675	415	415
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3291	8237	18129	28020	40385	2059	13385	8237	8237
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	0	0	0	0	0	0	0	0	0
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.470	0.588	0.647	0.666	0.678	0.588	0.588	0.588	0.588
-CATALYST (mills/kW-hr)	0.919	0.919	0.919	0.919	0.919	3.675	0.565	0.919	0.919
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.011	0.011	0.011	0.011	0.011	0.042	0.006	0.011	0.011
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.485	1.603	1.662	1.682	1.693	4.391	1.245	1.603	1.603
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.927	0.698	0.528	0.450	0.392	0.680	0.714	0.698	0.698
-VARIABLE O & M (mills/kW-Hr)	1.391	1.048	0.793	0.675	0.588	6.121	0.384	1.048	1 048
-CONSUMABLES (mills/kW-Hr)	1.485	1.603	1.662	1.682	1.693	4.391	1.245	1.603	1.603
-FUEL (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	18.44	13.98	10.59	9.01	7.84	13.98	13.98	13.67	15 83
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.07	7.34	6.01	5.38	4.91	27.15	4.80	7.25	7 87
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0 30
-LOWER CONTROLLED NOx (lb/MMBtu)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0 05
-LOWER NOx REDUCTION (tons/yr)	467	935	1869	2804	3972	234	1519	935	935
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	6798	5502	4503	4031	3681	20355	3598	5436	5899
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-HIGHER NOx REDUCTION (tons/yr)	374	748	1496	2243	3178	187	1215	748	748
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	8498	6877	5629	5039	4601	25443	4497	6794	7374

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g17tscru.wk1 SCR - UNCONTROLLED - TANGENTIAL-FIRED (Johnson, 1991) Case 17 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	105358	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	1951	3902	7804	11706	17560	3902	3902	3902	3902
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	4.51	3.41	2.59	2.20	1.87	3.41	3.41	3.41	3.41
-Fan Upgrade/Replace	12.85	9.74	7.38	6.28	5.34	9.74	9.74	9.74	9.74
-Structural	13.41	10.16	7.70	6.55	5.57	10.16	10.16	10.16	10 16
-Reagent Storage & Distribution	8.00	6.06	4.60	3.91	3.32	6.06	6.06	6.06	6.06
-DeNOx Reactor/Catalyst	32.02	24.27	18.39	15.64	13.30	24.27	24.27	24.27	24.27
-Control System	6.61	5.01	3.79	3.23	2.74	5.01	5.01	5.01	5.01
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	19.53	14.80	11.22	9.54	8.11	14.80	14.80	14.80	14.80
-Construction/Installation Labor	0.77	0.59	0.44	0.38	0.32	0.59	0.59	0.59	0.59
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	97.70	74.04	56.11	47.71	40.57	74.04	74.04	74.04	74.04
-GENERAL FACILITIES (GF) 10% of PCC	9.77	7.40	5.61	4.77	4.06	7.40	7.40	7.40	7.40
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	9.77	7.40	5.61	4.77	4.06	7.40	7.40	7.40	7.40
-PROCESS CONTINGENCY (Proc) 10% of PCC	9.77	7.40	5.61	4.77	4.06	7.40	7.40	7.40	7.40
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 40%	46.90	35.54	26.93	22.90	19.47	35.54	35.54	35.54	35.54
TOTAL PLANT COSTS (TPC) (1991$/kW) =	174	132	100	85	72	132	132	132	132
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	174	132	100	85	72	132	132	132	132
-ROYALTY ALLOWANCE 0.5% of PCC	0.49	0.37	0.28	0.24	0.20	0.37	0.37	0.37	0 37
-PREPRODUCTION COSTS 2% of TPC	3.48	2.64	2.00	1.70	1.44	2.64	2.64	2.64	2.64
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	178	135	102	87	74	135	135	135	135
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.094	0.041	0.268	0.165	0.165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	6.956	5.272	3.995	3.397	2.889	5 272	5 272	5 272	5 272
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.912	0.682	0.515	0.439	0.375	0.645	0 713	0.682	0 682
FIXED O & M COSTS ($/kW-yr) =	3.25	2.45	1.85	1.58	1 34	0.60	4 06	2.45	2 45
VARIABLE O & M COSTS (mills/kW-hr) =	1.391	1.048	0.793	0.675	0.575	6 121	0 384	1.048	1 048

NOx CONTROL COSTS - GAS/OIL BOILERS g17tscru.wk1 SCR - UNCONTROLLED - TANGENTIAL-FIRED (Johnson, 1991) Case 17 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	208	415	830	1246	1868	104	675	415	415
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3291	8237	18129	28020	42858	2059	13385	8237	8237
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	0	0	0	0	0	0	0	0	0
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.470	0.588	0.647	0.666	0.680	0.588	0.588	0.588	0.588
-CATALYST (mills/kW-hr)	0.919	0.919	0.919	0.919	0.919	3.675	0.565	0.919	0.919
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.011	0.011	0.011	0.011	0.011	0.042	0.006	0.011	0.011
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.485	1.603	1.662	1.682	1.695	4.391	1.245	1.603	1.603
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.927	0.698	0.528	0.450	0.383	0.680	0.714	0.698	0.698
-VARIABLE O & M (mills/kW-Hr)	1.391	1.048	0.793	0.675	0.575	6.121	0.384	1.048	1.048
-CONSUMABLES (mills/kW-Hr)	1.485	1.603	1.662	1.682	1.695	4.391	1.245	1.603	1.603
-FUEL (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	18.44	13.98	10.59	9.01	7.66	13.98	13.98	13.67	15.83
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.07	7.34	6.01	5.38	4.84	27.15	4.80	7.25	7.87
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
-LOWER CONTROLLED NOx (lb/MMBtu)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
-LOWER NOx REDUCTION (tons/yr)	467	935	1869	2804	4206	234	1519	935	935
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	6798	5502	4503	4031	3628	20355	3598	5436	5899
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-HIGHER NOx REDUCTION (tons/yr)	374	748	1496	2243	3365	187	1215	748	748
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	8498	6877	5629	5039	4535	25443	4497	6794	7374

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

NOx CONTROL COSTS - GAS/OIL BOILERS g18tscrc.wk1 SCR - CONTROLLED - TANGENTIAL-FIRED (Johnson, 1991) Case 18 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
BOILER AND FUEL SPECIFICATIONS									
BOILER AGE (Years)	25	25	25	25	25	25	25	15	40
BOILER BOOK LIFE (Years)	35	35	35	35	35	35	35	45	20
ANNUAL DISCOUNT (INTEREST) RATE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
CAPACITY FACTOR	0.40	0.40	0.40	0.40	0.40	0.10	0.65	0.40	0.40
COAL HHV (Btu/lb)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NATURAL GAS HHV (Btu/lb)	22000	22000	22000	22000	22000	22000	22000	22000	22000
OIL HHV (Btu/lb)	18200	18200	18200	18200	18200	18200	18200	18200	18200
OIL FRACTION	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
FUEL ASH CONTENT (% wt)									
GROSS HEAT RATE (Btu/kW-hr)	10670	10670	10670	10670	10670	10670	10670	10670	10670
EFFICIENCY LOSS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
REBURN FRACTION									
FLUE GAS FLOWRATE (@STP:68F:14.7psia)(1000 ft^3/hr)	11706	23413	46826	70239	105358	23413	23413	23413	23413
NH3/NO RATIO FOR SCR (molar)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
CATALYST LIFE (yrs)	4	4	4	4	4	4	4	4	4
CATALYST VOLUME (ft^3)	1951	3902	7804	11706	17560	3902	3902	3902	3902
UREA NSR (molar)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL LEVELIZATION (RECOVERY) FACTOR	0.104	0.104	0.104	0.104	0.104	0.104	0.104	0.101	0.117
CAPITAL COSTS									
PROCESS COSTS (1991$/kW):									
-Burners	----	-----	-----	-----	-----	-----	-----	-----	-----
-Ducting	4.51	3.41	2.59	2.20	1.87	3.41	3.41	3.41	3.41
-Fan Upgrade/Replace	12.85	9.74	7.38	6.28	5.34	9.74	9.74	9.74	9.74
-Structural	13.41	10.16	7.70	6.55	5.57	10.16	10.16	10.16	10.16
-Reagent Storage & Distribution	8.00	6.06	4.60	3.91	3.32	6.06	6.06	6.06	6 06
-DeNOx Reactor/Catalyst	32.02	24.27	18.39	15.64	13.30	24.27	24.27	24.27	24.27
-Control System	6.61	5.01	3.79	3.23	2.74	5.01	5.01	5.01	5.01
-Flue Gas Heat Exchanger	----	-----	-----	-----	-----	-----	-----	-----	-----
-Air Heater	19.53	14.80	11.22	9.54	8.11	14.80	14.80	14.80	14.80
-Construction/Installation Labor	0.77	0.59	0.44	0.38	0.32	0.59	0 59	0.59	0 59
TOTAL PROCESS CAPITAL COSTS (PCC) (1991$/kW) =	97.70	74.04	56.11	47.71	40.57	74.04	74.04	74.04	74.04
-GENERAL FACILITIES (GF) 10% of PCC	9.77	7.40	5.61	4.77	4.06	7.40	7.40	7.40	7.40
-ENGINEERING/HOME OFFICE FEES (EHOF) 10% of PCC	9.77	7.40	5.61	4.77	4.06	7.40	7.40	7.40	7.40
-PROCESS CONTINGENCY (Proc) 10% of PCC	9.77	7.40	5.61	4.77	4.06	7.40	7.40	7.40	7 40
-PROJECT CONTINGENCY (% of PCC+EHOF+Proc) 40%	46.90	35.54	26.93	22.90	19.47	35.54	35.54	35.54	35.54
TOTAL PLANT COSTS (TPC) (1991$/kW) =	174	132	100	85	72	132	132	132	132
-ESCALATION (0%)	0	0	0	0	0	0	0	0	0
-AFDC (0%)	0	0	0	0	0	0	0	0	0
TOTAL PLANT INVESTMENT (1991$/kW) =	174	132	100	85	72	132	132	132	132
-ROYALTY ALLOWANCE 0.5% of PCC	0.49	0.37	0.28	0.24	0.20	0.37	0.37	0.37	0.37
-PREPRODUCTION COSTS 2% of TPC	3.48	2.64	2.00	1.70	1.44	2.64	2.64	2.64	2.64
-INVENTORY CAPITAL (0%)	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL REQUIREMENT (TCR) (1991$/kW) =	178	135	102	87	74	135	135	135	135
OPERATING AND MAINTENANCE COSTS (O & M)									
-OPERATING LABOR (OL) ($/kW-yr)	0.256	0.165	0.119	0.104	0.094	0.041	0.268	0.165	0.165
-MAINTENANCE COSTS (MC) ($/kW-yr) 4% of TPC	6.956	5.272	3.995	3.397	2.889	5.272	5.272	5.272	5 272
-ADMIN/SUPPORT LABOR ($/kW-yr) 30% of OL+0.4MC	0.912	0.682	0.515	0.439	0.375	0.645	0.713	0.682	0 682
FIXED O & M COSTS ($/kW-yr) =	3.25	2.45	1.85	1.58	1.34	0.60	4 06	2.45	2.45
VARIABLE O & M COSTS (mills/kW-hr) =	1.391	1.048	0.793	0.675	0 575	6.121	0.384	1.048	1 048

NOx CONTROL COSTS - GAS/OIL BOILERS g18tscrc.wk1 SCR - CONTROLLED - TANGENTIAL-FIRED (Johnson, 1991) Case 18 | SIZE (MW)	EFFECT OF CAPACITY					EFFECT OF C.F.		EFFECT OF AGE	
	100	200	400	600	900	200	200	200	200
CONSUMABLES PENALTY									
-AMMONIA (tons/yr)	138	277	554	830	1246	69	450	277	277
-UREA (tons/yr)	0	0	0	0	0	0	0	0	0
-ELECTRICITY (MW-hrs/yr)	3291	8237	18129	28020	42858	2059	13385	8237	8237
-COAL (tons/yr)	0	0	0	0	0	0	0	0	0
-OIL (bbl/yr)	0	0	0	0	0	0	0	0	0
-GAS (1000 ft^3/yr)	0	0	0	0	0	0	0	0	0
CONSUMABLES OPERATING COSTS (Excluding Fuel)									
-AMMONIA (mills/kW-hr)	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057
-UREA (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-ELECTRICITY (mills/kW-hr)	0.470	0.588	0.647	0.666	0.680	0.588	0.588	0.588	0.588
-CATALYST (mills/kW-hr)	0.919	0.919	0.919	0.919	0.919	3.675	0.565	0.919	0.919
-CATALYST WASTE DISPOSAL (mills/kW-hr)	0.011	0.011	0.011	0.011	0.011	0.042	0.006	0.011	0.011
TOTAL CONSUMABLES (Excluding Fuel) (mills/kW-hr) =	1.456	1.574	1.633	1.653	1.666	4.362	1.217	1.574	1.574
FUEL COSTS									
-COAL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-OIL (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-GAS (mills/kW-hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED O & M COSTS									
-FIXED O & M (mills/kW-hr)	0.927	0.698	0.528	0.450	0.383	0.680	0.714	0.698	0.698
-VARIABLE O & M (mills/kW-Hr)	1.391	1.048	0.793	0.675	0.575	6.121	0.384	1.048	1.048
-CONSUMABLES (mills/kW-Hr)	1.456	1.574	1.633	1.653	1.666	4.362	1.217	1.574	1.574
-FUEL (mills/kW-Hr)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LEVELIZED CAPITAL CHARGES ($/kW-yr) =	18.44	13.98	10.59	9.01	7.66	13.98	13.98	13.67	15.83
LEVELIZED BUSBAR COST (mills/kW-hr) =	9.04	7.31	5.98	5.35	4.81	27.12	4.77	7.22	7.84
EMISSIONS									
-UNCONTROLLED NOx (lb/MMBtu)	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
-LOWER CONTROLLED NOx (lb/MMBtu)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
-LOWER NOx REDUCTION (tons/yr)	280	561	1122	1682	2524	140	911	561	561
-LOWER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	11294	9134	7470	6683	6010	33889	5960	9023	9796
-HIGHER CONTROLLED NOx (lb/MMBtu)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
-HIGHER NOx REDUCTION (tons/yr)	187	374	748	1122	1682	93	608	374	374
-HIGHER NOx REMOVAL COST EFFECTIVENESS ($/ton) =	16941	13701	11204	10024	9015	50833	8940	13535	14694

APPLICABLE UNIT PRICING	UNIT COST	
COAL ($/ton)	45.84	Electric Power Monthly, March 1991
OIL ($/bbl)	22.85	Electric Power Monthly, March 1991
GAS ($/1000 ft^3)	2.61	Gas Facts, 1991
AMMONIA ($/ton)	145.00	Robie, 1991
UREA ($/ton)	220.00	BP Chemical, 1991
ELECTRICITY ($/kW-hr)	0.05	Robie, 1991
CATALYST COST ($/ft^3)	660.00	Robie, 1991
CATALYST SOLID WASTE DISPOSAL ($/ton)	315.00	Robie, 1991
OPERATING LABOR ($/man-hr)	21.45	Robie, 1991

APPENDIX H

DATA BASE ON CO, HC, AND UBC UNDER BASELINE AND LOW-NO_x OPERATION

NESCAUM UTILITY BOILER NOx EVALUATION -- CO AND UNBURNED CARBON DATA, PULVERIZED COAL FIRED BOILERS

Boiler Unit and Capacity (maximum continuous rating, MWe)	Load (MWe)	NOx Control Type	Burner Type	Fuel	Emissions				Source
					NOx lb/MMBtu	NOx ppm@3%O2	UBC %	CO ppm@3%O2	
WALL-FIRED UNITS:									
Scotland, UK: Drax Unit 6 Opposed Fired, 660 MW	660	LNB	Mark III	U.K. Bituminous	0.44	328	6.5		King, 1991
					0.53	395	3		
					0.55	410	2		
					0.45	340	4		
					0.52	393	2.5		
					0.58	435	2		
					0.49	365	3		
					0.52	391	1.8		
					0.45	335	3.3		
					0.51	382	1.5		
					0.56	422	1		
		baseline			1.11	832	1-1.5		
EPDC Matsuura Unit 1 Opposed Fired, 1000 MW	1000	LNB	HT-NR	Bituminous	0.13-0.30	101-228	.45-4		Uemura, 1991
CEGB Eggborough Unit 2 Wall Fired, 500 MW	500	LNB	CF/SF MK-II		0.60	450	3		Beard, 1989
					0.57	425	7		
					0.52	390	5.5		
					0.45	340	7.2		
		baseline (unit 1)			1.03	770	1.2		
					0.92	690	1.9		
					0.84	630	2.5		
Alleghany Power: Pleasants Unit 2 Opposed Fired, 650 MW	626	OFA		U.S. Bituminous	0.65	490	2.5	40-60	Vatsky, 1989
		LNB	CF/SF		0.41	310	2.5	40	
		LNB, OFA	CF/SF with OFA		0.33	250		100	
		baseline			0.95	710	2.5	40	
ELKRAFT Power Co.: ASNAES Unit 4 Wall Fired, 285 MW	278	LNB	BWE	H.Vol Polish	0.49	370	<5		Pederson, 1991
		baseline			0.99	740	5		
Ohio Edison: Edgewater Unit 4 Wall Fired, 100 MW	100	LNB	XCL		0.47	350	6	60	La Rue, 1989
					0.53	400	2.8	115	
		baseline			0.71	530	2.2	20	
UK: NEI-ICL Wall Fired, 500 MW	500	LNB	F. Wall		0.36	270	7	50	Allen, 1991
					0.45	335	5.5	25	
					0.45	340	5	10	
					0.49	370	4	10	
					0.53	400	3.5	10	
					0.60	450	1.75	15	
					0.64	480	0.75	9	
		baseline			0.73	550	5	80	
					0.76	570	5.2	60	
					0.77	580	5	45	
					0.79	590	4.5	38	
					0.80	600	4.3	30	
					0.83	620	3.8	25	
					0.85	640	3.2	23	
					0.88	660	2.6	21	
					0.91	685	2.1	20	

NESCAUM UTILITY BOILER NOx EVALUATION -- CO AND UNBURNED CARBON DATA, PULVERIZED COAL FIRED BOILERS

Boiler Unit and Capacity (maximum continuous rating, MWe)	Load (MWe)	NOx Control Type	Burner Type	Fuel	Emissions				Source
					NOx lb/MMBtu	NOx ppm@3%O2	UBC %	CO ppm@3%O2	
WALL-FIRED UNITS:									
Germany: RWE Wall Fired, 600 MW	75	OFA		Rhinisch brown coal	0.27	205		20	Hein, 1989
					0.26	195		20	
					0.24	180		20	
					0.21	160		20	
					0.19	145		20	
					0.17	125		20	
					0.15	110		180	
					0.13	100		260	
	600	baseline			0.45	340		10	
					0.42	317		10	
					0.37	280		10	
					0.29	220		100	
					0.26	195		400	
ENEL: Vado Ligure Unit 4 Opposed Fired, 330 MW	330	OFA	Cell	U.S. Eastern Bituminous	0.52	390	12	8	Tarli, 1991
					0.57	427	8	8	
					0.63	472	7.7	8	
		baseline			0.78	584	6		
					0.93	700	5.5		
Riley Stoker Coal Burner Test Facility, Wall Fired 100 MMBtu/hr		LNB	CCV	U.S. Eastern Bituminous	0.31	230		100	Lisauskas, 1989
					0.40	300		78	
					0.45	340		75	
					0.59	440		60	
		baseline	Flare		0.67	500		75	
					0.72	540		67	
					0.79	590		65	
Arizona Pub. Svc.: Four Corners 4 Opposed Fired, 800 MW	800	LNB	CF/SF	U.S. Sub-bituminous	0.50	375	0.1	20-40	Vatsky, Lu, 1991
		baseline			1.27	950	0.1	<40	
Georgia Power Co.: Hammond Unit 4 Oposed Fired, 500 MW	500	LNB		U.S. Eastern Bituminous	0.55-0.7	412-525	5.5-8	10-20	Sorge, 1992
		AOFA			0.9-0.95	675-712	9.5-10	10-15	
		baseline			1-1.2	750-900	4.5-5	30-100	

NESCAUM UTILITY BOILER NOx EVALUATION -- CO AND UNBURNED CARBON DATA, PULVERIZED COAL FIRED BOILERS

Boiler Unit and Capacity (maximum continuous rating, MWe)	Load (MWe)	NOx Control Type	Burner Type	Fuel	Emissions				Source
					NOx lb/MMBtu	NOx ppm@3%O2	UBC %	CO ppm@3%O2	
TANGENTIAL UNITS:									
ENEL: Fusina Unit 2 Tangential, 160 MW	160	LNB/OFA	LNCFS	U.S. Eastern Bituminous	0.55	410	8.5	<= 40	Grusha, 1991
					0.53	400	8.8	<= 40	
					0.47	350	9	<= 40	
					0.40	300	9.5	<= 40	
					0.35	265	10	<= 40	
					0.30	225	10.25	<= 40	
		baseline			0.67	500	7-9		
PSCC: Valmont Unit 5 Tangential, 165 MW	165	LNB/OFA	LNCFS	U.S. Western Bituminous	0.27	200	1.6	<30	Hunt, Grusha, 1991
					0.40.	300	1.6	<30	
					0.67	500	1.6	<30	
		baseline			0.53	400	1.6	<30	
Kansas P&L: Lawrence Unit 5 Tangential, 400 MW	300	LNB/OFA	PM	U.S. Bituminous	0.24-0.3	180-225	0.3		Thompson, 1989
		baseline			0.43-0.5	325-375	0.4		
PSCC: Cherokee Unit 4 Tangential, 350 MW	380	LNB/OFA	LNCFS	U.S. Western Bituminous	0.27	205	2.5	<30	Hunt, 1991
		baseline			0.53	400	2.2	<30	
Labadie Unit 4 Tangential, 600 MW	600	LNB/OFA	LNCFS	U.S. Bitum/ Subbituminous	0.45	340			Smith, 1992
		baseline			0.50-0.69	375-520	0.5-1	5-35	
Lansing Smith Unit 2 Tangential, 200 MW	200	LNB/OFA	LNCFS II	U.S. Eastern Bituminous	0.40	300	3.8-5.	20-32	Hardman, 199
		LNB/OFA	LNCFS III		0.34	255	5.5-6.	25-65	
		baseline			0.6-0.65	450-490	4.4-5	10-15	
CYCLONE UNITS:									
Nelson Dewey Unit 2 Cyclone, 100 MW	100	coal reburn		U.S. Bituminous	0.36	270		90	Newell, 1992
		baseline			0.81	610		90	
Ohio Edison: Niles Unit 1 Cyclone, 108 MW	108	NG reburn		U.S. Eastern Bituminous	0.37	275	30-35	35	Booth, 1991
		baseline			0.94	705	30-35	<30	
Babcock & Wilcox SBS (pilot scale) Cyclone, 6 MMBtu/hr		reburn		Indiana bitum	0.4-0.8	300-600	5.1	<50	Yagiela, 1991
		baseline			1.37	1025	3.5	<50	
TURBO FURNACE:									
PSI: Wabash Unit 5 Turbo Furnace, 105 MW	95	LNB	Riley CCV		0.45	340	3.5		Penterson, 1991
		baseline			0.85	640	10		

NESCAUM UTILITY BOILER NOx EVALUATION -- CO EMISSION DATA, NATURAL GAS FIRED BOILERS

Boiler Unit and Capacity (maximum continuous rating, MWe)	Load (MWe)	NOx Control Type	Burner Type	Emissions NOx lb/MMBtu	Emissions NOx ppm@3%O2	Emissions CO ppm@3%O2	Source
ENEL: Fusina Unit 2 Tangential, 160 MW	160	LNB	LNCF	0.05	40	175	Grusha, Tarli, 1991
				0.05	45	150	
				0.06	50	110	
				0.07	60	80	
				0.08	70	70	
				0.10	80	60	
				0.12	100	50	
				0.17	145	47	
		baseline		0.21	175	40	
ENEL: Rossano Unit 4 Opposed Fired, 320 MW	320	BOOS (12 burners)		0.26	220	280	Benanti, 1989
				0.28	235	120	
				0.29	245	90	
				0.31	263	32	
		baseline (18 burners)		0.36	300	160	
				0.40	330	40	
				0.41	340	25	
ENEL: Sermide Unit 3 Opposed Fired, 320 MW	320	BOOS (12 burners)		0.10	83	32	Tarli, 1991
		baseline		0.40	333		
B&W XCL Burner Wall Fired, 120 MBtu/hr		LNB	XCL	0.09	74	36	La Rue, 1989
				0.08	65	46	
				0.06	50	35	
				0.04	33	36	
		baseline		0.06-0.13	50-110		
Germany: Arzberg Unit 6 Wall Fired, 220 MW	220	LNB	STS	0.06	50	15	Lisauskas, 1991
		baseline		0.36	300		
San Diego G&E: South Bay Unit 1 Wall Fired, 150 MW	150	fuel biasing		0.13	110	800	Quartucy, 1987
		BOOS		0.14	113	3700	
		baseline		0.20	170	250	
Southern Cal Ed, Alamitos Unit 6 Opposed Fired, 480 MW	260-480	LNB w/BOOS &FGR	Todd	0.02-0.08	16-65	0-330	Bayard de Volo, 1991
		BOOS &FGR		0.03-0.13	25-112	0-700	
		baseline		0.84	700		
Southern Cal Ed, Redondo Unit 8 Opposed Fired, 480 MW	480	BOOS		0.07	56	90	McDannel 1991
		baseline		0.10	87	100	
New England Power Service Co. LNB Evaluation Project Wall Fired, 80 MBtu/hr		LNB	TTL/MG22.	0.07	60	12	Afonso 1991
				0.06	54	12	

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4. TITLE AND SUBTITLE Evaluation and Costing of NOx Controls for Existing Utility Boilers in the NESCAUM Region		5. REPORT DATE December 1992
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7. AUTHOR(S) Carlo Castaldini		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Acurex Environmental Corporation, Post Office Box 7044, Mountain View, California 94039		10. PROGRAM ELEMENT NO.
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15. SUPPLEMENTARY NOTES

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16. ABSTRACT

This Technical Report discusses NOx controls for utility boilers in the Northeast States for Coordinated Air Use Management (NESCAUM) region. The document discusses:

- Utility boiler population profile in the NESCAUM region
- Uncontrolled NOx emissions and factors that affect NOx emissions
- Available NOx controls and their levels of performance
- Cost methodology for determining the costs of NOx controls
- Costs and cost effectiveness of NOx controls
- Impacts of NOx controls on combustible emissions

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
NOx Emissions Control techniques for NOx emissions from utility boilers Utility Boilers Combustion Modifications		

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS *(This Report)*	21. NO OF PAGES 426
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